UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2023

Commission file number 1-10447

COTERRA ENERGY INC.

(Exact name of registrant as specified in its charter)

Delaware	**04-3072771**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza,
840 Gessner Road, Suite 1400, Houston, Texas 77024
(Address of principal executive offices including ZIP code)
(281) 589-4600
(Registrant’s telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.10 per share	CTRA	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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ 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 ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐

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

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

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

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

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

The aggregate market value of Common Stock, par value $0.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2023) was approximately $18.8 billion.

As of February 21, 2024, there were 751,847,432 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 1, 2024 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

FORWARD-LOOKING INFORMATION

This report includes forward-looking statements within the meaning of federal securities laws. All statements, other than statements of historical fact, included in this report are forward-looking statements. Such forward-looking statements include, but are not limited to, statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging and risk management activities, timing and amount of capital expenditures and other statements that are not historical facts contained in this report. The words “expect,” “project,” “estimate,” “believe,” “anticipate,” “intend,” “budget,” “plan,” “forecast,” “target,” “predict,” “potential,” “possible,” “may,” “should,” “could,” “would,” “will,” “strategy,” “outlook” and similar expressions are also intended to identify forward-looking statements. We can provide no assurance that the forward-looking statements contained in this report will occur as expected, and actual results may differ materially from those included in this report. Forward-looking statements are based on current expectations and assumptions that involve a number of risks and uncertainties that could cause actual results to differ materially from those included in this report. These risks and uncertainties include, without limitation, the impact of public health crises, including pandemics (such as the coronavirus (“COVID-19”) pandemic) and epidemics and any related company or governmental policies or actions, the availability of cash on hand and other sources of liquidity to fund our capital expenditures, actions by, or disputes among or between, members of OPEC+, market factors, market prices (including geographic basis differentials) of oil and natural gas, impacts of inflation, labor shortages and economic disruption, including as a result of instability in the banking sector, geopolitical disruptions such as the war in Ukraine or the conflict in the Middle East, results of future drilling and marketing activities, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission (“SEC”) filings. Additional important risks, uncertainties and other factors are described in “Risk Factors” in Part I. Item 1A of this report. Forward-looking statements are based on the estimates and opinions of management at the time the statements are made. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof.

Investors should note that we announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, we may use the Investors section of our website (www.coterra.com) to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on our website is not part of, and is not incorporated into, this report.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and included within this Annual Report on Form 10-K:

Bbl.   One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf.   One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent.

Btu. British thermal units, a measure of heating value.

DD&A. Depletion, depreciation and amortization.

EHS. Environmental, health and safety.

ESG. Environmental, social and governance.

G&A. General and administrative.

GAAP. Accounting principles generally accepted in the U.S.

GHG. Greenhouse gas.

Hydraulic fracturing. A technology involving the injection of fluids, which typically include small amounts of several chemical additives and sand, into a wellbore under high pressure in order to create fractures in the formation that allow oil or natural gas to flow more freely to the wellbore.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Net Acres or Net Wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

Net Production. Gross production multiplied by net revenue interest.

NGLs. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

NYSE. New York Stock Exchange.

OPEC+. Organization of Petroleum Exporting Countries and other oil exporting nations.

Proved developed reserves. Reserves that can be expected to be recovered: (1) 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 (2) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves. Those quantities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions and operating methods prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

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

PUD. Proved undeveloped.

SEC. Securities and Exchange Commission.

Tcf. One trillion cubic feet of natural gas.

U.S. United States.

Table of Contents

WTI. West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil used as a benchmark in oil pricing.

WTI Midland. WTI Midland Index price as quoted by Argus Americas Crude.

Energy equivalent is determined using the ratio of one barrel of crude oil, condensate or NGL to six Mcf of natural gas.

PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Coterra Energy Inc. (“Coterra,” the “Company,” “our,” “we” and “us”) is an independent oil and gas company engaged in the development, exploration and production of oil, natural gas and NGLs. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable development programs. We operate in one segment, oil and natural gas development, exploration and production, in the continental U.S.

Our headquarters is located in Houston, Texas. We also maintain regional offices in Pittsburgh, Pennsylvania, Midland, Texas, and Tulsa, Oklahoma, as well as field offices near our operations.

STRATEGY

Coterra is a premier U.S.-focused exploration and production company. We embrace innovation, technology and data, as we work to create value for our investors and the communities where we operate. We believe the following strategic priorities will help drive value creation and long-term success.

Generate Sustainable Returns. Our premier assets across multiple basins provide commodity diversification and strong cash flow generation through the commodity price cycles that, combined with our disciplined capital investment, give us confidence in our ability to provide returns to our stockholders that we believe to be sustainable. Demonstrating our continued confidence in our business model, since the consummation of the merger with Cimarex Energy Co. (“Cimarex”) through December 31, 2023, we have increased our annual base dividend $0.36 per share, or 82 percent, on our common stock to $0.80 per share and have returned over $3.5 billion to stockholders through dividends. In February 2024, our Board of Directors increased our annual base dividend to $0.84 per share. Since our initial share repurchase program, which began in early 2022, we have repurchased 65 million shares for $1.7 billion, at a weighted average share price of $25.75 per share. As of December 31, 2023, we had $1.6 billion remaining on our current $2.0 billion share repurchase program. In total, since the consummation of the merger with Cimarex, we have returned $5.2 billion to stockholders through dividends and share repurchases and have retired $874 million of debt. We remain committed to returning 50 percent or more of our annual free cash flow to our stockholders through dividends and our share repurchase program, while maintaining our industry-leading balance sheet.

Disciplined Capital Allocation Across Top-Tier Position. Our asset portfolio offers scale, capital optionality and low break-even investment options. We anticipate our drilling inventory will be developed over the next 15 to 20 years. We are committed to maintaining a disciplined capital investment strategy and using technology and innovation to maximize capital efficiency and create value for stockholders. With operations in the Permian Basin, Marcellus Shale, and Anadarko Basin, our asset portfolio is both commodity and geographically diversified, allowing for capital allocation flexibility that may prove opportunistic in navigating commodity price cycles. During 2023 and 2022, we invested 57 percent and 31 percent, respectively, of our cash flow from operations in our drilling program, and in 2024 we expect to invest approximately 50 percent of our estimated cash flow from operations, based on recent strip prices.

Maintain Financial Strength. Maintaining an industry-leading balance sheet with significant financial flexibility is imperative in a cyclical industry exposed to commodity price volatility. Our asset base, revenue diversity, low-cost structure and strong balance sheet provide us with the flexibility to thrive across various commodity price environments. With a year-end 2023 cash balance of $956 million and $1.5 billion of unused commitments under our revolving credit agreement, we believe we are well positioned to maintain our balance sheet strength.

Focus on Safe, Responsible and Sustainable Operations. Responsible development of oil and natural gas resources provides opportunity for a bright future, one built through technology and innovation that offers prosperity for communities around the world. Our focus on operational excellence is based on making our operations more environmentally and socially sustainable. We actively implement technology across our operations from the design phase to equipment improvements to limit our methane emissions and flaring activity. Safety of our employees and contractors is paramount. We empower all employees and contractors to utilize our Stop Work Authority program, which allows them to stop any work at any time if they are uncomfortable, discover a dangerous condition, or suspect any other EHS hazard. We also focus on practical and sustainable environmental initiatives that promote efficient use of fresh and produced water, eliminate or mitigate releases, and minimize land surface impact. We are committed to being responsible stewards of our resources and implementing sustainable practices. We have published our 2023 Sustainability Report, which includes more information related to our sustainability practices, on our website at www.coterra.com. The information on our website is not part of, and is not incorporated into, this Annual Report on Form 10-K or any other report we may file with or furnish to the SEC (and is not deemed filed herewith), whether before or after the date of this Annual Report on Form 10-K and irrespective of any general incorporation language therein.

2024 OUTLOOK

Our 2024 capital program is expected to be approximately $1.75 billion to $1.95 billion, a decrease of 12 percent (at the mid-point) from $2.1 billion in 2023. We expect to turn-in-line 132 to 158 total net wells in 2024 across our three core operating areas. Approximately 60 percent of our drilling and completion capital will be invested in the Permian Basin, 23 percent in the Marcellus Shale and 17 percent in the Anadarko Basin (at the mid-point).

DESCRIPTION OF PROPERTIES

Our operations are primarily concentrated in three core operating areas—the Permian Basin in west Texas and southeast New Mexico, the Marcellus Shale in northeast Pennsylvania and the Anadarko Basin in the Mid-Continent region in Oklahoma.

Permian Basin

Our properties are principally located in the western half of the Permian Basin where we currently hold approximately 296,000 net acres in our core operating area in the Delaware Basin. Our development activities are primarily focused on the Wolfcamp Shale and the Bone Spring formation in Culberson and Reeves Counties in Texas and Lea and Eddy Counties in New Mexico. Our 2023 net production from the Permian Basin was 233 MBoe per day, representing 35 percent of our total equivalent production for the year. Net oil production in 2023 averaged 90 MBbl per day, representing 93 percent of our total company oil production. As of December 31, 2023, we had a total of 1,083.0 producing net wells in the Permian Basin, of which approximately 89 percent are operated by us.

During 2023, we invested $970 million in the Permian Basin, and had seven drilling rigs operating at year end.

Marcellus Shale

Our properties are principally located in Susquehanna County, Pennsylvania, where we currently hold approximately 186,000 net acres in the dry gas window of the Marcellus Shale. Our 2023 net production in the Marcellus Shale was 377 MBoe per day, representing 57 percent of our total equivalent production for the year. Net natural gas production in 2023 averaged 2,263 MMcf per day, representing 78 percent of our total natural gas production. As of December 31, 2023, we had a total of 1,108.2 producing net wells in the Marcellus Shale, of which approximately 99 percent are operated by us.

During 2023, we invested $912 million in the Marcellus Shale, and had two drilling rigs operating at year end.

Anadarko Basin

Our properties are located in the Mid-Continent region in Oklahoma where we currently hold approximately 182,000 net acres. Our development activities are primarily focused on both the Woodford Shale and the Meramec formations. Our 2023 net production in the Anadarko Basin was 56 MBoe per day, representing eight percent of our total equivalent production for the year. As of December 31, 2023, we had a total of 509.9 producing net wells in the Anadarko Basin, of which approximately 61 percent are operated by us.

During 2023, we invested $158 million in the Anadarko Basin and had one rig operating at year end.

Other Properties

Ancillary to our exploration, development and production operations, we operate a number of natural gas gathering and saltwater gathering and disposal systems. The majority of this infrastructure is located in Texas and directly supports our Permian Basin operations. Our gathering systems enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate and intrastate pipelines and natural gas processing facilities and to transport produced water to new wells for re-use in completions activities and to disposal facilities. In addition, we can engage in development drilling without relying on third parties to transport our natural gas or produced water and while incurring only the incremental costs of pipeline and compressor additions to our system.

ACQUISITIONS

On October 1, 2021, we completed a merger transaction (the “Merger”) with Cimarex. Cimarex is an oil and gas exploration and production company with operations in Texas, New Mexico and Oklahoma. Under the terms of the merger agreement relating to the Merger (the “Merger Agreement”), and subject to certain exceptions specified in the Merger Agreement, each eligible share of Cimarex common stock was converted into the right to receive 4.0146 shares of our common stock at closing. As a result of the completion of the Merger, we issued approximately 408.2 million shares of common stock to Cimarex stockholders (excluding shares that were awarded in replacement of certain previously outstanding Cimarex restricted share awards). Additionally, on October 1, 2021, we changed our name to Coterra Energy Inc.

Operational information set forth in this Annual Report on Form 10-K does not include the activity of Cimarex for periods prior to the completion of the Merger.

MARKETING

Substantially all of our oil and natural gas production is sold under both long-term and short-term sales contracts at market-sensitive prices. We sell oil, natural gas and NGLs to a broad portfolio of customers, including industrial customers, local distribution companies, oil and gas marketers, major energy companies, pipeline companies and power generation facilities.

We also incur gathering and transportation expenses when we move our oil and natural gas production from wellhead markets to other downstream markets.

To date, we have not experienced significant difficulty in transporting or marketing our production as it becomes available; however, there is no assurance that we will always be able to transport and market all of our production.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell natural gas. We believe we will have sufficient production quantities to meet our commitments, but we may be required to purchase natural gas from third parties to satisfy shortfalls, should they occur.

A summary of our firm sales commitments as of December 31, 2023 are set forth in the table below:

	Natural Gas (in Bcf)
2024	601
2025	577
2026	572
2027	549
2028	526

We utilize part of our firm transportation capacity to deliver natural gas under the majority of these firm sales contracts and have entered into numerous agreements for transportation of our production. Some of these contracts have volumetric requirements that could result in monetary shortfall penalties if our production is inadequate to meet such requirements. However, we do not anticipate incurring any penalties based on our current proved reserves and production levels from which we can fulfill these obligations.

RISK MANAGEMENT

We use derivative financial instruments to manage price risk associated with our production. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Quantitative and Qualitative Disclosures about Market Risk” and Note 5 of the Notes to the Consolidated Financial Statements, “Derivative Instruments” for further discussion related to our use of derivatives.

PROVED OIL AND GAS RESERVES

The following table presents our estimated proved reserves by commodity as of the dates indicated:

	December 31,		
	2023	2022	2021
Oil (MBbl)			
Proved developed reserves	173,392	168,649	153,010
Proved undeveloped reserves	75,821	71,107	36,419
	249,213	239,756	189,429
Natural Gas (Bcf)			
Proved developed reserves	8,590	8,543	10,691
Proved undeveloped reserves	1,935	2,630	4,204
	10,525	11,173	14,895
NGLs (MBbl)			
Proved developed reserves	234,306	224,706	193,598
Proved undeveloped reserves	83,150	72,059	27,017
	317,456	296,765	220,615
Oil equivalent (MBoe)	2,320,757	2,398,666	2,892,582

At December 31, 2023, our interests in the Dimock field, which is primarily located in Susquehanna County, Pennsylvania in the Marcellus Shale account for approximately 60 percent of our total proved reserves. There are no other fields which represent 15 percent or more of our total proved reserves.

For additional information regarding estimates of our net proved and proved undeveloped reserves, the qualifications of the preparers of our reserves estimates, the evaluation of such estimates by our independent petroleum consultants, our processes and controls with respect to our reserves estimates and other information about our reserves, including the risks inherent in our estimates of proved reserves, refer to the Supplemental Oil and Gas Information included in Item 8 and “Risk Factors—Business and Operational Risks—Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A.

Table of Contents

PRODUCTION, SALES PRICE AND PRODUCTION COSTS

The following table presents historical information about our total and average daily production volumes for oil, natural gas and NGLs; average oil, natural gas and NGL sales prices; and average production costs per equivalent:

	Year Ended December 31,		
	2023	2022	2021 (1)
Production Volumes			
Oil (MBbl)	35,110	31,926	8,150
Natural gas (Bcf)	1,053	1,024	911
NGL (MBbl)	32,932	28,697	7,104
Equivalents (MBoe)	243,497	231,342	167,113
Average Daily Production Volumes			
Oil (MBbl)	96	87	89
Natural gas (MMcf)	2,884	2,806	2,492
NGL (MBbl)	90	79	77
Equivalents (MBoe)	667	634	660
Average Sales Price			
Excluding Derivative Settlements			
Oil ($/Bbl)	$ 75.97	$ 94.47	$ 75.61
Natural gas ($/Mcf)	$ 2.18	$ 5.34	$ 3.07
NGL ($/Bbl)	$ 19.56	$ 33.58	$ 34.18
Including Derivative Settlements			
Oil ($/Bbl)	$ 76.07	$ 84.33	$ 60.35
Natural gas ($/Mcf)	$ 2.44	$ 4.91	$ 2.73
NGL ($/Bbl)	$ 19.56	33.58	$ 34.18
Average Production Costs ($/Boe)	$ 2.01	$ 1.84	$ 0.77

(1) On October 1, 2021, we completed the Merger. The production information presented in this table includes Cimarex production for the period subsequent to that date.

The following table presents historical information about our total and average daily natural gas production volumes associated with our interests in the Dimock field. There was no oil or NGL production associated with our interests in the Dimock field.

	Year Ended December 31,		
	2023	2022	2021
Production Volumes			
Natural gas (Bcf)	826	805	853
Equivalents (MBoe)	137,647	134,097	142,223
Average Daily Production Volumes			
Natural gas (MMcf)	2,263	2,204	2,338
Equivalents (MBoe)	377	367	390

Table of Contents

ACREAGE

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under oil and gas mineral leases. These leases provide us the right to develop oil and natural gas on the properties. Their primary terms generally range in length from approximately three to 10 years, and these leases generally are held for longer periods once production is established.

The following table summarizes our gross and net developed and undeveloped leasehold acreage at December 31, 2023:

	Acreage					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Core Acreage						
Permian Basin						
New Mexico	141,319	98,212	55,339	38,654	196,658	136,866
Texas	204,971	136,845	27,825	21,892	232,796	158,737
	346,290	235,057	83,164	60,546	429,454	295,603
Marcellus Shale						
Pennsylvania	173,225	171,625	15,024	14,030	188,249	185,655
Anadarko Basin						
Oklahoma	320,080	146,987	69,123	34,526	389,203	181,513
Noncore Acreage						
Arizona	17,207	17,207	2,097,841	2,097,841	2,115,048	2,115,048
California	—	—	383,487	383,487	383,487	383,487
Nevada	440	1	1,007,167	1,007,167	1,007,607	1,007,168
New Mexico	10,655	2,436	1,640,195	1,634,459	1,650,850	1,636,895
Pennsylvania	—	—	114,199	64,044	114,199	64,044
West Virginia	—	—	607,347	575,691	607,347	575,691
Other	128,713	45,069	298,421	172,990	427,134	218,059
	157,015	64,713	6,148,657	5,935,679	6,305,672	6,000,392
	996,610	618,382	6,315,968	6,044,781	7,312,578	6,663,163

Total Net Undeveloped Acreage Expiration

The table below summarizes by year and operating area our undeveloped acreage expirations in the next three years. In most cases, the drilling of a commercial well will hold the acreage beyond the expiration.

	Acreage					
	2024		2025		2026	
	Gross	Net	Gross	Net	Gross	Net
Core Acreage						
Permian Basin	3	3	—	—	47	7
Marcellus Shale	1,208	1,208	1,860	1,848	550	550
Anadarko Basin	700	134	520	125	40	1
Noncore Acreage	1,303	1,242	—	—	—	—
	3,214	2,587	2,380	1,973	637	558

Expiring acreage in our core operating areas in 2024, 2025 and 2026 represents less than one percent of our total undeveloped acreage. At December 31, 2023, we had no PUD reserves recorded on undeveloped acreage that were scheduled for development beyond the expiration dates of the undeveloped acreage or outside of our core operating area.

WELL SUMMARY

The following table presents our ownership in productive oil and natural gas wells at December 31, 2023. This summary includes oil and natural gas wells in which we have a working interest:

	Gross	Net
Natural Gas	3,374	1,865.6
Oil	2,523	837.0
Total[1]	5,897	2,702.6

(1) Total percentage of gross and net operated wells is 49 percent and 88 percent, respectively.

DRILLING ACTIVITY

The table below presents wells that we drilled and completed or in which we participated in the drilling and completion. This information should not be considered indicative of future performance, nor should a correlation be assumed as a result of the number of productive wells drilled, the quantities of reserves found or the economic value.

	Year Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	288	183.3	284	173.9	114	99.9
Dry	—	—	1	0.7	—	—
Total	288	183.3	285	174.6	114	99.9
Acquired Wells	—	—	—	—	7,266	1,715.3

During the year ended December 31, 2023, we completed 98 gross wells (62.7 net) that were drilled in prior years.

The following table sets forth information about wells for which drilling was in progress or which were drilled but uncompleted at December 31, 2023, which are not included in the above table:

	Drilling In Progress		Drilled But Uncompleted	
	Gross	Net	Gross	Net
Development wells	31	19.9	72	48.4
Exploratory wells	1	0.5	—	—
Total	32	20.4	72	48.4

OTHER BUSINESS MATTERS

Title to Properties

We believe that we have satisfactory title to all of our producing properties and leases in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes or development obligations under oil and gas leases. As is customary in the industry in the case of undeveloped properties, we conduct preliminary investigations of record title at the time of lease acquisition. We conduct more complete investigations prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Competition

The oil and gas industry is highly competitive, and we experience strong competition where we operate. We primarily compete with integrated, independent and other energy companies for the sale and transportation of our oil and natural gas production to pipelines, marketing companies and end users. Many of these competitors have greater financial, technical and personnel resources than we have. The effect of these competitive factors cannot be predicted.

Price, contract terms, availability of rigs and related equipment and quality of service, including infrastructure availability and distribution efficiencies affect competition. We believe that our concentrated acreage positions and our access to both third-party and Company-owned gathering and pipeline infrastructure in our core operating areas, along with our expected activity level and the related services and equipment that we have secured for the upcoming years, enhance our competitive position.

Major Customers

During the year ended December 31, 2023, two customers accounted for approximately 19 percent and 17 percent of our total sales. During the year ended December 31, 2022, two customers accounted for approximately 13 percent and 11 percent of our total sales.

If any one of our major customers were to stop purchasing our production, we believe there are other purchasers to whom we could sell our production. If multiple significant customers were to stop purchasing our production, we expect to have sufficient alternative markets to handle any sales disruptions despite any initial disruptions that may occur.

We regularly monitor the creditworthiness of our customers and may require parent company guarantees, letters of credit or prepayments when necessary. Historically, losses associated with uncollectible receivables have not been significant.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. These regulations include requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled and the unitization or pooling of oil and gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The laws and regulations limit the amounts of oil and natural gas we can produce from our wells as well as the number of wells, and the locations where, we can drill. Because these laws and regulations are often amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry often increases the cost of doing business and, consequently, affects our profitability. These laws and regulations, however, do not affect us differently than others in the industry.

Regulation of Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas we produce and the manner in which our production is transported and marketed. Under the U.S. Natural Gas Act of 1938 (the “NGA”), the U.S. Natural Gas Policy

Act of 1978 (the “NGPA”) and the regulations promulgated under those statutes, the U.S. Federal Energy Regulatory Commission (the “FERC”) regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective beginning in January 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all “first sales” of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC granted to all producers such as us a “blanket certificate of public convenience and necessity” authorizing the sale of natural gas for resale without further FERC approvals. As a result of this policy, all of our produced natural gas is sold at market prices, subject to the terms of any private contracts that may be in effect. Under the provisions of the Energy Policy Act of 2005 (“2005 Act”), the NGA was amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established regulations intended to increase natural gas pricing transparency by, among other things, requiring market participants to report their gas sales transactions annually to the FERC. The 2005 Act also significantly increased the penalties for violations of the NGA and NGPA and the FERC’s regulations thereunder up to $1 million per day per violation. This maximum penalty authority established by statute has been and will continue to be adjusted periodically for inflation. The current maximum penalty is approximately $1.5 million per day per violation. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties and procedure under its enforcement program.

Under the NGPA, natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes “gathering” under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering and production facilities meet the test for non-jurisdictional “gathering” systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

Our natural gas sales prices continue to be affected by intrastate and interstate gas transportation regulation because the cost of transporting the natural gas once sold to the consuming market is a factor in the prices we receive. Beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted a series of rule makings that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, requiring interstate pipeline companies to separate their wholesale gas marketing business from their gas transportation business and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their natural gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants. Most pipelines have also implemented the large-scale divestiture of their natural gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines are required to provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. As a result of the FERC requiring natural gas pipeline companies to separate marketing and transportation services, sellers and buyers of natural gas have gained direct access to pipeline transportation services, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, we cannot predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by the U.S. Congress or the various state legislatures and what effect, if any, such proposals might have on us. Further, we cannot predict whether the recent trend toward federal deregulation of the natural gas industry will continue or what effect future policies will have on our sale of gas.

Federal Regulation of Swap Transactions

We use derivative financial instruments such as collar, swap and basis swap agreements to attempt to manage price risk due to the impact of changes in commodity prices on our operating results and cash flows. The Commodity Exchange Act provides the U.S. Commodity Futures Trading Commission (the “CFTC”) with jurisdiction to regulate the over-the-counter (“OTC”) derivatives market (which includes the sorts of financial instruments we use) and participants in that market. We endeavor to ensure that our OTC derivatives transactions comply with applicable CFTC regulations. Although the CFTC does not currently require the clearing of OTC commodity derivatives transactions of the types that we use, we believe that our use of swaps to hedge against changes in commodity prices qualifies us as a commercial end-user, which would exempt us from a future requirements to centrally clear our commodity swaps. Nevertheless, future changes in CFTC regulations could increase the cost of entering into derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of swaps, our results of operations may become more volatile and our cash flows may be less predictable.

Federal Regulation of Petroleum

Sales of crude oil and NGLs are not regulated and are made at market prices. However, the price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines, which are regulated by the FERC under the Interstate Commerce Act (“ICA”). The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service and that such service not be unduly discriminatory or preferential.

Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may increase or decrease the cost of transporting crude oil and NGLs by interstate pipeline. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2015, to implement this required five-year redetermination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.23 percent should be the oil pricing index for the five-year period beginning July 1, 2016. In 2020, the FERC concluded its five-year index review to establish the new adder for crude oil and liquids pipeline rates subject to indexing. The FERC issued an order on December 17, 2020 establishing an index level of Producer Price Index for Finished Goods plus 0.78 percent for the five-year period commencing July 1, 2021. The result of indexing is a “ceiling rate” for each rate, which is the maximum at which the pipeline may set its interstate transportation rates. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Rates are subject to challenge by protest when they are filed or changed. For indexed rates, complaints alleging that the rates are unjust and unreasonable may only be pursued if the complainant can show that a substantial change has occurred since the enactment of Energy Policy Act of 1992 in either the economic circumstances of the pipeline or in the nature of the services provided that were a basis for the rate. There is no such limitation on complaints alleging that the pipelines’ rates or terms and conditions of service are unduly discriminatory or preferential. We are unable to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index or any potential future challenges to pipelines’ rates.

Environmental and Safety Regulations

General. Our operations are subject to extensive and stringent federal, state and local laws and regulations governing the protection of the environment. These laws and regulations can change, restrict or otherwise impact our business in many ways, including the handling or disposal of waste material, planning for future activities to avoid or mitigate harm to threatened or endangered species, and requiring the installation and operation of emissions or pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both. Regulations can increase the cost of planning, designing, installing and operating, and can affect the timing of installing and operating, oil and natural gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities and potential suspension or cessation of operations under certain conditions related to environmental considerations or compliance issues are part of oil and natural gas production operations. We can provide no assurance that we will not incur significant costs and liabilities. Also, it is possible that other developments, such as stricter environmental laws and regulations and claims for damages to property or persons resulting from oil and natural gas production could result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and natural gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators), clean up contamination (including groundwater contamination by prior owners or operators) or perform plugging operations to prevent future contamination.

We generate some wastes that are hazardous wastes subject to the Resource Conservation and Recovery Act (the “RCRA”) and comparable state statutes, as well as wastes that are exempt from such regulation. The U.S. Environmental Protection Agency (the “EPA”) limits the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess the need to regulate exploration and production related oil and gas wastes exempt from regulation as hazardous wastes under RCRA under Subtitle D applicable to non-hazardous solid waste. The consent decree required the EPA to propose a rulemaking by March 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. In April 2019, the EPA issued its determination that based on its review, including consideration of state regulatory programs, it was not necessary at the time to revise Subtitle D regulations to address the management of oil and gas wastes. In the future, we could be subject to more rigorous and costly disposal requirements than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the “Superfund” law, and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of business, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA's hazardous substances definition. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and implementing regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the U.S. The term "waters of the U.S." has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns joint and several strict liability to each responsible party for oil removal costs and a variety of public and private damages. The OPA also imposes ongoing requirements on operators, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe that we are in substantial compliance with the OPA and related federal regulations to the extent applicable to our operations.

Endangered Species Act. The Endangered Species Act (the "ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service (the "FWS") may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, to bald and golden eagles under the Bald and Golden Eagle Protection Act, and to certain species under state law. We conduct operations in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons.

On June 1, 2021, the FWS proposed to list two distinct population segments ("DPS") of the lesser prairie-chicken ("LPC") under the ESA. The Southern DPS, located in eastern New Mexico and the southwest Texas panhandle was proposed to be listed as endangered and the Northern DPS, located in southeastern Colorado, southcentral to southwestern Kansas, western Oklahoma and the northeast Texas panhandle, was proposed to be listed as threatened. On November 25, 2022, the FWS finalized the proposed rule, listing the southern DPS of the lesser prairie-chicken as endangered and the northern DPS of the lesser prairie-chicken as threatened. On July 27, 2023, the U.S. House of Representatives voted to use the Congressional Review Act to reverse the LPC listing. On September 26, 2023 President Biden vetoed Congress' resolution to reverse the LPC listing. On September 28, 2023, the U.S. Senate voted and failed to override the President's veto. On November 3, 2023, the U.S. House of Representatives passed an appropriations bill for the U.S. Department of Interior for fiscal year 2023, which provides, in part, that no funds may be used to implement, administer, or enforce the listing of the LPC. Listing of the LPC as a threatened or endangered species will impose restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm or otherwise result in a “taking” of this species. Regulatory impacts on landowners and businesses from an ultimate decision to list the LPC could be limited for those landowners and businesses who have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies (“WAFWA”), pursuant to which such parties agreed to take steps to protect the LPC’s habitat and to pay a mitigation fee if its actions harm the lesser prairie-chicken’s habitat. We have entered into a voluntary Candidate Conservation Agreement (a “CCA”) with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the LPC.

On February 9, 2018, the FWS announced the listing of the Texas Hornshell, a freshwater mussel species in areas where we operate in the Permian Basin, including New Mexico and Texas, as an endangered species. In March 2018, we entered into a CCA concerning voluntary conservation actions with respect to the Texas Hornshell.

Participating in CCAs could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays or limitations may be significant. Listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations (“NGOs”) work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The listing of the Mexican Long Nosed Bat, whose habitat includes the Permian Basin where we operate, and the Dunes Sagebrush Lizard (proposed to be listed as endangered under the ESA on July 3, 2023) in the Permian Basin, are examples of the NGOs’ influence on ESA listing decisions.

On December 1, 2020, the FWS proposed to list the Peppered Chub as endangered under the ESA. The proposed listing was finalized and published on February 28, 2022. The Peppered Chub is a freshwater fish that historically was found in the South Canadian, Cimarron and Arkansas rivers within New Mexico, Texas, Oklahoma and Kansas. We have operations near the South Canadian River in Oklahoma that may be impacted by the listing of the Peppered Chub as endangered. The increase in endangered species listings, such as the Peppered Chub, may limit our ability to explore for or produce oil and gas in certain areas or cause us to incur additional costs.

Clean Water Act. The Federal Water Pollution Control Act (the "Clean Water Act") and implementing regulations, which are primarily executed through a system of permits, also govern the discharge of certain pollutants into waters of the U.S. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewater to facilities owned by others that are the source of water discharges to resolve non-compliance. We believe that we substantially comply with the applicable provisions of the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to the federal Clean Air Act (the "Clean Air Act") and comparable local and state laws and regulations to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permitting requirements. Federal and state laws designed to control toxic air pollutants and greenhouse gases might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve any failures to comply strictly with air regulations or permits. However, in the event of non-compliance, regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. We believe that we substantially comply with applicable emission standards and permitting requirements under local, state and federal laws and regulations.

Some of our producing wells and associated facilities are subject to restrictive air emission limitations and permitting requirements. Two examples are the EPA's source aggregation rule and the EPA's New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). In June 2016, the EPA published a final rule concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry, and, as a result, aggregating our oil and gas facilities for permitting may result in increased complexity and cost of, and time required for, air permitting. Particularly with respect to obtaining pre-construction permits, the final aggregation rule has added costs and caused delays in operations.

In 2012, the EPA published final NSPS and NESHAP that amended the existing NSPS and NESHAP for the oil and natural gas sector. In June 2016, the EPA published a final rule that updated and expanded the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In June 2017, the EPA proposed a two-year stay of certain requirements contained in the June 2016 rule and, in November 2017, issued a notice of data availability in support of the stay proposal and provided a 30-day comment period on the information provided. In March 2018, the EPA published a final rule that amended two narrow provisions of the NSPS, removing the requirement for completion of delayed repair during emergency or unscheduled vent blowdowns. In September 2020, the EPA published a final rule amending the 2012 and 2016 NSPS for the oil and natural gas sector that removed transmission and storage sources from the oil and natural gas industry source category and rescinded the methane requirements applicable to the production and processing sources. On June 30, 2021, President Biden signed into law a joint Congressional resolution under the Congressional Review Act disapproving the September 2020 rule amending the EPA's 2012 and 2016 NSPS standards for the oil and natural gas sector. On November 15, 2021, the EPA proposed rules to reduce methane emissions from both new and existing oil and natural gas industry sources and published supplemental rules regarding the same on December 6, 2022. On December 2, 2023, during the United Nations Climate Change Conference in the United Arab Emirates ("COP28"), the EPA announced its final methane rules, which impose several new methane emission requirements on the oil and gas industry. For additional information, please read "Risk Factors—Legal, Regulatory and Governmental Risks— Federal, state and local laws and regulations, judicial actions and regulatory initiatives related to oil and gas development and the use of hydraulic fracturing could result in increased costs and operating restrictions or delays and adversely affect our business, financial condition, results of operations and cash flows" in Item 1A.

In October 2015, the EPA adopted a lower national ambient air quality standard for ozone. The revised standard resulted in additional areas being designated as ozone non-attainment, which could lead to requirements for additional emissions control equipment and the imposition of more stringent permit requirements on facilities in those areas. The EPA completed its final area designations under the new ozone standard in July 2018. If we are unable to comply with air pollution regulations or to obtain permits for emissions associated with our operations, we could be required to forego or implement modifications to certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil or criminal penalties for noncompliance. Obtaining permits may delay the development of our oil and natural gas projects, including the construction and operation of facilities.

Safe Drinking Water Act. The Safe Drinking Water Act ("SDWA") and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface placement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. Substantially all of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and natural gas wells. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the U.S. federal, state and local levels have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or to restrict or prohibit the activity altogether. States in which we operate also have adopted, or have stated intentions to adopt, laws or regulations that mandate further restrictions on hydraulic fracturing, such as imposing more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations and establishing standards for the capture of air emissions released during hydraulic fracturing. In addition to state measures, local land use restrictions, such as city ordinances, may restrict drilling in general or hydraulic fracturing in particular. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and natural gas production activities using hydraulic fracturing techniques, which could have an adverse effect on oil and natural gas production activities, including operational delays or increased operating costs in the production of oil and natural gas, or could make it more difficult to perform hydraulic fracturing. For example, Pennsylvania's Act 13 of 2012 amended the state's Oil and Gas Act to, among other things, increase civil penalties and strengthen the authority of the Pennsylvania Department of Environmental Protection over the issuance of drilling permits. Although the Pennsylvania Supreme Court struck down portions of Act 13 that made statewide rules on oil and gas preempt local zoning rules, this could lead to additional local restrictions on oil and gas activity in the state.

At the federal level, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released its final report in December 2016. It concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. This study and other studies that may be undertaken by the EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and regulatory mechanisms. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing practices.

Our inability to locate sufficient amounts of water, or to dispose of or recycle water used or produced in our exploration and production operations, could adversely impact our operations. For water sourcing, we first seek to use non-potable water supplies, or recycled produced water for our operational needs. In certain areas, there may be insufficient water available for drilling and completion activities. Water must then be obtained from other sources and transported to the drilling site. Our operations in certain areas could be adversely impacted if we are unable to secure sufficient amounts of water or to dispose of or recycle the water used in our operations. The imposition of new environmental and other regulations, as well as produced water disposal well limits or moratoriums in areas of seismicity, could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of waste such as produced water and drilling fluids. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition. In June 2016, the EPA published final pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works. The regulations were developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. In response to these actions, operators, including us, have begun to rely more on recycling of water that flows back from the wellbore following hydraulic fracturing ("flowback water") and produced water from well sites as a preferred alternative to disposal.

Greenhouse Gas and Climate Change Laws and Regulations. In response to studies suggesting that emissions of carbon dioxide and certain other greenhouse gas ("GHG"), including methane, may be contributing to global climate change, there is increasing focus by local, state, regional, national and international regulatory bodies as well as by investors and the public on GHG emissions and climate change issues. In December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change (the "UNFCCC") in Paris, France in creating an agreement (the "Paris Agreement") that requires member countries to review and "represent a progression" in their intended nationally determined contributions ("NDC") of GHGs, which set GHG emission reduction goals every five years beginning in 2020. In 2019, the U.S. withdrew from the Paris Agreement. The current Presidential administration has made climate change a central priority. On January 20, 2021, his first day in office, President Biden took action to reverse the withdrawal of the previous administration from the Paris Agreement so that the U.S. could rejoin as a party to the agreement. The U.S. officially rejoined the Paris Agreement on February 19, 2021, and in April 2021 submitted its NDC. The U.S. NDC sets an economy-wide target of net GHG emissions reduction from 2005 levels of 50-52 percent by 2030. The specific measures to be taken in furtherance of achieving this target have not been established, but the NDC submission indicated that a "whole government approach" will be used to achieve this target, including regulatory, technology and policy initiatives designed to reduce the generation of GHG emissions and to incentivize the capture and geologic sequestration or utilization of carbon dioxide that would otherwise be emitted in the atmosphere. Also on his first day in office, President Biden signed an executive order on climate action and reconvened an interagency working group to establish interim and final social costs of three GHGs: carbon dioxide, nitrous oxide, and methane. Carbon dioxide is released during the combustion of fossil fuels, including oil, natural gas, and NGLs, and methane is a primary component of natural gas. The Biden administration stated it will use updated social cost figures to inform federal regulations and major agency actions and to justify aggressive climate action as the U.S. moves toward a "100 percent clean energy" economy with net-zero GHG emissions. Furthermore, at COP28 in December 2023, more than 190 governments reached a non-binding agreement to transition away from fossil fuels and encourage the growth and expansion of renewable energy.

Although the U.S. Congress has considered legislation designed to reduce emissions of GHGs in recent years, it has not adopted any significant GHG legislation. However, the 2021 Infrastructure and Investment Jobs Act passed by Congress on November 6, 2021 included measures aimed at decarbonization to address climate change, including funding for replacing transit vehicles, including buses, with zero- and low-emission vehicles and for the deployment of an electric vehicle charging network nationwide. This legislation, and other future laws, that promote a shift toward electric vehicles could adversely affect the demand for our products. Moreover, in the absence of federal GHG legislation, a number of state and regional efforts have emerged. These include measures aimed at tracking and reducing GHG emissions through cap-and-trade programs, which typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs. In addition, a coalition of over 20 governors of U.S. states formed the U.S. Climate Alliance to advance the objectives of the Paris Agreement, and several U.S. cities have committed to advance the objectives of the Paris Agreement at the state or local level as well. To this end, California's governor issued an executive order on September 23, 2020 ordering actions to pursue GHG emissions reductions, including a direction to the California State Air Resources Board to develop and propose regulations to require increasing volumes of new zero-emission passenger vehicles and trucks sold in California over time, with a targeted ban of the sale of new gasoline vehicles by 2035.

At the federal level, the EPA has begun to regulate carbon dioxide and other GHGs under existing provisions of the Clean Air Act. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act that establish Prevention of Significant Deterioration ("PSD") and Title V permit reviews for GHG emissions from certain large stationary sources that are otherwise subject to PSD and Title V permitting requirements. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including, among others, certain oil and gas production facilities on an annual basis, which includes certain of our operations. The EPA widened the scope of annual GHG reporting to include, not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems, and transmission pipelines. More recently, on November 15, 2021, the EPA proposed rules to reduce methane emissions from new and modified sources in the oil and gas sector and published proposed supplemental rules regarding the same on December 6, 2022. On December 2, 2023, during COP28, the EPA announced its final methane rules, which impose several new methane emission requirements on the oil and gas industry. The Inflation Reduction Act of 2022 ("IRA") established the Methane Emissions Reduction Program, which imposes a charge on methane emissions from certain petroleum and natural gas facilities, which may apply to our operations in the future and may require us to expend material sums.

If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. Any future laws or regulations that limit emissions of GHGs from our equipment and operations could require us to both develop and implement new practices aimed at reducing GHG emissions, such as emissions control technologies, which could increase our operating costs and could adversely affect demand for the oil and gas that we produce. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future implementation or adoption of legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. At this time, it is not possible to quantify the impact of any such future developments on our business.

Occupational Safety and Health Act and Other Laws and Regulations. We are subject to the requirements of the U.S. federal Occupational Safety and Health Act (the “Occupational Safety and Health Act”) and comparable state laws. The Occupational Safety and Health Act hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state laws require that we organize and disclose information about hazardous materials used or produced in our operations. Also, pursuant to the Occupational Safety and Health Act, the Occupational Safety and Health Administration (the “OSHA”) has established a variety of standards related to workplace exposure to hazardous substances and employee health and safety.

Human Capital Resources

As of December 31, 2023, we had 894 Coterra employees, 285 of whom were located in our headquarters in Houston, Texas and 227 of whom were located in our regional offices in Midland, Texas, Tulsa, Oklahoma and Pittsburgh, Pennsylvania. We had a total of 382 employees in production field locations across our regional offices. Of our total employee population, 564 were salaried and 330 were hourly. Additionally, we have 189 employees that are employed by our wholly-owned subsidiary, GasSearch Drilling Services Corporation (“GDS”), which is a service company engaged in water hauling and site preparation exclusively for our Marcellus Shale operations. Of our GDS employees, 16 were salaried and 173 were hourly. We believe that our relations with our employees are favorable. None of our employees are represented pursuant to a collective bargaining agreement.

Our ability to attract, retain and develop the highest quality employees is a vital component of our success.

In managing our people, we seek to:

- promote a safe and healthy workplace;
- have a results-focused culture centered on transparency and open communication;
- attract, retain and develop a highly qualified, motivated and diverse workforce;
- maintain a conservatively managed headcount to minimize workforce fluctuations;
- provide opportunities for career growth, learning and development; and
- offer highly competitive compensation and benefits packages.

We believe these practices, further described below, are the key drivers in our development of current and future talent and leadership as well as employee engagement and retention.

Recruiting, Hiring and Advancement. Due to the cyclical nature of our business and the fluctuations in activity that can occur, we manage our headcount carefully. We provide employees with opportunities to learn new roles and develop the breadth and depth of their skills to ensure a collaborative environment, strong talent and future leadership. This also helps to minimize layoffs and overall staff fluctuations when downturns occur. When a position needs to be filled, we generally seek to promote current top-performing employees before going to outside sources for a new hire. We believe this practice helps to build future leadership and to reduce voluntary turnover among our workforce by providing employees with new challenges and opportunities throughout their careers.

When we hire from outside the Company, we identify qualified candidates by promoting the position internally for referrals, engaging in recruiting through our website and online platforms, utilizing recruiting services and attending job fairs. We also have a well-established internship program that feeds top talent into our technical functions. In our recruiting efforts, we foster a culture of mutual respect and compliance with all applicable federal, state and local laws governing nondiscrimination in employment. We seek to increase the diversity of our workforce in our external hiring practices. We ask our recruiting partners to provide diverse slates of candidates and 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, including recruiting, hiring, placement, promotion, evaluation, leaves of absence, compensation and training.

Compensation and Benefits. Our focus on providing competitive total compensation and benefits to our employees is a core value and a key driver of our retention program. We design our compensation programs to provide compensation that is competitive with our industry peers and rewards superior performance and, for managers and executives, aligns compensation with our performance and incentivizes the achievement of superior operating results. We do this through a total rewards program that provides:

- base wages or salaries that are competitive for the position and considered for increases annually based on employee performance, business performance and industry outlook;
- incentives that reward individual and Company performance, such as performance bonuses, management discretionary bonuses, field operational bonuses and short-term and long-term incentive programs;
- retirement benefits, including dollar-for-dollar matching contributions and discretionary employer retirement contributions to a tax-qualified defined contribution savings plan for all employees and other non-qualified retirement programs;
- comprehensive health and welfare benefits, including medical insurance, prescription drug benefits, dental insurance, vision insurance, life insurance, accident insurance, short and long-term disability benefits, employee assistance program and health savings accounts;
- tuition reimbursement for eligible employees, scholarship program and matching charitable contributions program; and
- time off, sick time, parental leave and holiday time.

We believe our compensation and benefits package is a strong retention tool and promotes personal health and financial security within our workforce.

Health and Safety. The health and safety of our employees is one of our core values for sustainable operations. This value is reflected in our strong safety culture that emphasizes personal responsibility and safety leadership, both for our employees and our contractors that are on our worksites. Our safety programs are built on a foundation that emphasizes personal safety and includes a Stop Work Authority program that empowers employees and contractors to stop work if they discover a dangerous condition or other serious EHS hazard. Our comprehensive EHS management system establishes a corporate governance framework for EHS compliance and performance and covers all elements of our operating lifecycle.

Website Access to Company Reports

We make available free of charge through our website, www.coterra.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by us. Information on our website, including our 2023 Sustainability Report, is not a part of, and is not incorporated into, this Annual Report on Form 10-K or any other report we may file with or furnish to the SEC (and is not deemed filed herewith), whether before or after the date of this Annual Report on Form 10-K and irrespective of any general incorporation language therein. Furthermore, references to our website URLs are intended to be inactive textual references only.

Corporate Governance Matters

Our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Audit Committee Charter, Compensation Committee Charter, Governance and Social Responsibility

Committee Charter and Environment, Health & Safety Committee Charter are available on our website at www.coterra.com. Requests for copies of these documents can also be made in writing to Corporate Secretary at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas 77024.

ITEM 1A. RISK FACTORS

Business and Operational Risks

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, financial condition, results of operations and cash flows, as well as adversely affect the value of an investment in our common stock, debt securities, or preferred stock.

Commodity prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prices we receive for the oil, natural gas and NGLs that we sell. Lower commodity prices may reduce the amount of oil, natural gas and NGLs that we can produce economically, while higher commodity prices could cause us to experience periods of higher costs. Historically, commodity prices have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Wide fluctuations in commodity prices may result from relatively minor changes in the supply of and demand for oil, natural gas and NGLs, market uncertainty and a variety of additional factors that are beyond our control, including global events or conditions that affect supply and demand, such as pandemics, the war in Ukraine, conflict in the Middle East and other geopolitical risks and sanctions, the actions of OPEC+ members and climate change. Any substantial or extended decline in future commodity prices would have a material adverse effect on our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. If commodity prices decline significantly for a sustained period of time, the lower prices may cause us to reduce our planned drilling program or adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations. Furthermore, substantial, extended decreases in commodity prices may render certain projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow, our cost of capital and our ability to access capital markets, increase our costs under our revolving credit agreement and limit our ability to execute aspects of our business plans.

Future commodity price declines may result in write-downs of the carrying amount of our oil and gas properties, which could materially and adversely affect our results of operations.

The value of our oil and gas properties depends on commodity prices. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material downward adjustments to our estimated proved reserves and could result in an impairment charge and a corresponding write-down of the carrying amount of our oil and gas properties.

We evaluate our oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate a property’s carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future commodity prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices decline, there could be a significant revision to the carrying amounts of oil and gas properties in the future.

Drilling, completing and operating oil and natural gas wells are high-risk activities.

Our growth is materially dependent upon the success of our drilling program. Drilling for oil and natural gas involves numerous risks, including the risk that no commercially productive reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control. Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition.

Our operations present hazards and risks that require significant oversight and are subject to numerous possible disruptions from unexpected events.

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, product spills, and cybersecurity incidents, such as unauthorized access to data or systems, among other risks. Our operations are also subject to broader global events and conditions, including public health crises, pandemics, epidemics, war or civil unrest, acts of terror, weather events and natural disasters, including those that are related to or exacerbated by climate change. Such hazards and risks could impact our business in the areas in which we operate, and our business and operations may be disrupted if we fail to respond in an appropriate manner to such hazards and risks or if we are unable to efficiently restore or replace affected operational components and capacity. Furthermore, our insurance may not cover such, or be adequate to compensate us for all resulting losses. The cost of insurance may increase and the availability of insurance may decrease, as a result of climate change or other factors. The occurrence of any event not covered or fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

Reserves engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserves data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as assumptions relating to commodity prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. For example, our total company proved reserves decreased by approximately 17 percent year over year at December 31, 2022. For more information on such revision, refer to the Supplemental Oil and Gas Information included in Item 8.

Results of drilling, testing and production subsequent to the date of a reserves estimate may justify revising the original estimate. Accordingly, initial reserves estimates often vary from the quantities of oil and natural gas that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Our future performance depends on our ability to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline as reserves are depleted, eventually resulting in a decrease in oil and natural gas production and lower revenues and cash flow from operations. Our future production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Additionally, there is no way to predict in advance of any exploration and development whether any particular location will yield sufficient quantities to recover drilling or completion costs or be economically viable. Low commodity prices may further limit the kinds of reserves that we can develop and produce economically. If we are unable to replace our current and future production, our revenues will decrease and our business, financial condition and results of operations may be adversely affected.

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

As of December 31, 2023, approximately 21 percent of our estimated proved reserves (by volume) were undeveloped. Developing PUD reserves requires significant capital expenditures, and the estimated future development costs associated with our PUD reserves may not equal our actual costs, development may not occur as scheduled and results of our development activities may not be as estimated. If we choose not to develop our PUD reserves, or if we are not otherwise able to develop them successfully, we will be required to remove them from our reported proved reserves. In addition, under the SEC’s reserves reporting rules, because PUD reserves generally may be recorded only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUD reserves that are no longer planned to be developed within this five-year time frame. Delays in the development of our PUD reserves, decreases in commodity prices and increases in costs to drill and develop such reserves may also result in some projects becoming uneconomic.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects depend on our ability to identify optimal strategies for our business. In developing our business plans, we considered allocating capital and other resources to various aspects of our business including well-development (primarily drilling and completion), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also consider our likely sources of capital. Notwithstanding the determinations made in the development of our 2024 plan, business opportunities not previously identified periodically may come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2024 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Our ability to sell our oil, natural gas and NGL production and the prices we receive for our production could be materially harmed if we fail to obtain adequate services such as gathering, transportation and processing.

The sale of our oil, natural gas and NGL production depends on a number of factors beyond our control, including the availability and capacity of gathering, transportation and processing facilities. We deliver the majority of our oil, natural gas and NGL production through gathering systems and pipelines that we do not own. The lack of available capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Third-party systems and facilities may be unavailable due to market conditions or mechanical or other reasons, and in some cases the resulting curtailments of production could lead to payment being required where we fail to deliver oil, natural gas and NGLs to meet minimum volume commitments. In addition, construction of new pipelines and building of required infrastructure may be slow. To the extent these services are unavailable, we would be unable to realize revenue from wells served by such facilities until suitable arrangements are made to market our production. Our failure to obtain these services on acceptable terms could materially harm our business.

Moreover, these availability and capacity issues are likely to occur in remote areas with less established infrastructure, such as our Permian Basin properties where we have significant oil and natural gas production. Any of these availability or capacity issues could negatively affect our operations, revenues and expenses. This could result in wells being shut in or awaiting a pipeline connection or capacity, which would adversely affect our results of operations and cash flows.

Acquired properties may not be worth what we pay to acquire them, due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include estimates of recoverable reserves, exploration and development potential, future commodity prices, operating costs, production taxes and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to assess fully the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface or environmental problems that may exist or arise.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We often assume certain liabilities, and we may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. At times, we acquire interests in properties on an “as is” basis with limited representations and warranties and limited remedies for breaches of such representations and warranties. In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties.

The integration of the businesses and properties we have acquired or may in the future acquire could be difficult and may divert management’s attention away from our existing operations.

The integration of the businesses and properties we have acquired or may in the future acquire could be difficult, and may divert management’s attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired businesses and properties while carrying on the ongoing operations of our business;

- the inability to retain key employees of the acquired business;
- the challenge of inconsistencies in standards, controls, procedures and policies of the acquired business;
- potential unknown liabilities, unforeseen expenses or higher-than-expected integration costs;
- an overall post-completion integration process that takes longer than originally anticipated;
- potential lack of operating experience in a geographic market of the acquired properties; and
- the possibility of faulty assumptions underlying our expectations.

If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. Our future success will depend, in part, on our ability to manage our expanded business, which may pose substantial challenges for management. We may also face increased scrutiny from governmental authorities as a result of the increase in the size of our business. There can be no assurances that we will be successful in our integration efforts.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. As of December 31, 2023, non-operated wells represented approximately 51 percent of our total owned gross wells, or 12 percent of our owned net wells. We have limited ability to influence or control the operation or future development of these non-operated properties and of properties we operate in joint ventures in which we may share control with third parties, including compliance with environmental, safety and other regulations or the amount of capital expenditures that we are required to fund with respect to them. An operator of our wells or a joint venture participant may not adequately perform operations, may breach applicable agreements or may fail to act in ways that are in our best interest, which could reduce our production and revenues and expose us to liabilities. Our dependence on the operator or a joint venture participant could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Many of our properties are in areas that may have been partially depleted or drained by offset (i.e., neighboring) wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing or operating wells that they own.

Many of our properties are in areas that may have been partially depleted or drained by earlier drilled offset wells. We have no control over offsetting operators who could take actions such as drilling and completing nearby wells, that could adversely affect our operations. When a new offset well is completed and produced, the pressure differential in the vicinity of the wellbore causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores), which could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. The possibility for these impacts may increase with respect to wells that are shut in as a response to lower commodity prices or the lack of pipeline and storage capacity. In addition, completion operations and other activities conducted on other nearby wells could cause us, in order to protect our existing wells, to shut in production for indefinite periods of time. Shutting in our wells and damage to our wells from offset completions could result in increased costs and could adversely affect the reserves and re-commenced production from such shut in wells.

We may lose leases if production is not established within the time periods specified in the leases or if we do not maintain production in paying quantities.

We could lose leases under certain circumstances if we do not maintain production in paying quantities or meet other lease requirements, and the amounts we spent for those leases could be lost. If we shut in wells in response to lower commodity prices or a lack of pipeline and storage capacity, we may face claims that we are not complying with lease provisions. In addition, the government also may impose new restrictions and regulations affecting our ability to drill, conduct hydraulic fracturing operations, and obtain necessary rights-of-way on federal lands, which could, in turn, result in the loss of federal leases. As of December 31, 2023, less than one percent of our net undeveloped acreage in our core operating areas will expire over the next three years. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Cyber-attacks targeting our systems, the oil and gas industry systems and infrastructure or the systems of our third-party service providers could adversely affect our business.

Our business, like the oil and gas industry in general, has become increasingly dependent on data, information systems, and digitally connected infrastructure, including technologies managed by third-party providers on whom we rely to help us collect, host or process information. We depend on this technology to, for example, record and store information like financial data, estimate quantities of oil and natural gas reserves, analyze and share operating data, and communicate internally and externally. Information and operational technology systems control nearly all of the oil and gas distribution systems in the U.S., which are necessary to transport our products to market. These systems also enable communications and provide a host of other support services for our business. In recent years (and, in large part, due to the COVID-19 pandemic), we have increased the use of remote networking and online conferencing services and technologies that enable employees to work outside of our corporate infrastructure, which exposes us to additional cybersecurity risks, including unauthorized access to proprietary, confidential, or other sensitive information.

Cyber-attacks are becoming more sophisticated and can include, but are not limited to, the use of malicious software, phishing scams, ransomware, attempts to gain unauthorized access to systems or data, or other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, such as personal information of our employees, and corruption of data. Unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data integrity issues, communication interruption or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our business and operations. If our information or operational technology systems cease to function properly or are breached, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyber-attack involving our information or operational technology systems and related infrastructure, or that of our business associates or partners, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, equipment damage, fires, explosions or environmental releases, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer’s or supplier’s data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

In addition, certain cyber incidents, such as reconnaissance campaigns, may remain undetected for an extended period, and our systems and insurance coverage for protecting against such cybersecurity risks may be costly and may not be sufficient. As cyber-attackers become more sophisticated, we may be required to expend significant additional resources to continue to protect our business or remediate the damage from cyber-attacks. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention, mitigation, and notification, and we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

Risks Related to our Indebtedness, Hedging Activities and Financial Position

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We make and expect to make substantial capital expenditures in connection with our development and production projects. We rely on access to both our revolving credit agreement and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Adverse economic and market conditions, could adversely affect our ability to access such sources of liquidity. Future challenges in the global financial system may adversely affect the terms on which we are able to obtain financing, which could impact our business, financial condition and access to capital. Our ability to access the capital markets may be restricted at a time when we want or need to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Additionally, such adverse economic and market conditions could impact our counterparties, including our receivables and our hedging counterparties, who may, as a result of such conditions, be unable to perform their obligations.

Risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

Our indebtedness could have adverse effects on our business, financial condition, results of operations and cash flows, including by requiring us to use a substantial portion of our cash flow to make debt service payments, which would reduce the funds that would otherwise be available for operations, returning cash flow from operations to stockholders and future business opportunities. As a result, our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be adversely impacted. Our ability to make payments on and to refinance our indebtedness will depend on our ability to generate cash in the future from operations, financings or asset sales. If we fail to make required payments or otherwise default on our debt, the lenders who hold such debt also could accelerate amounts due, which could potentially trigger a default or acceleration of other debt.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If commodity prices deteriorate from current levels, it could lead to reduced revenues, cash flow and earnings, which in turn could lead to a default under such agreements due to lack of covenant compliance. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of lower commodity prices could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to modify our capital program, sell non-strategic assets or opportunistically modify or increase our derivative instruments. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot provide assurance that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or at all. For more information about our debt agreements, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Financial Condition-Liquidity and Capital Resources.”

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for oil and natural gas.

We use financial derivative instruments to manage commodity price risk. While there are many different types of derivatives available, we generally utilize collar, swap and basis swap agreements to manage price risk more effectively.

While these derivatives reduce the impact of declines in commodity prices, these derivatives conversely limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production;
- production is less than expected; or
- a counterparty is unable to satisfy its obligations.

In addition, the CFTC has promulgated regulations to implement statutory requirements for derivatives transactions, including swaps. Although we believe that our use of swap transactions exempts us from certain regulatory requirements, the changes to the derivatives market regulation affect us directly and indirectly. These changes, as in effect and as continuing to be implemented, as well as a reduced liquidity in oil and gas derivative market, could increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of swaps, our results of operations may become more volatile, and our cash flows may be less predictable.

In addition, the use of financial derivative instruments involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We are unable to predict changes in a counterparty’s creditworthiness or ability to perform, and even if we could predict such changes accurately, our ability to negate such risk may be limited depending on market conditions and the contractual terms of the instruments. If any of our counterparties were to default on its obligations under our financial derivative instruments, such a default could (1) have a material adverse effect on our results of operations, (2) result in a larger percentage of our future production being subject to commodity price changes and (3) increase the likelihood that our financial derivative instruments may not achieve their intended strategic purposes.

We will continue to evaluate the benefit of utilizing derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A for further discussion concerning our use of derivatives.

Legal, Regulatory and Governmental Risks

ESG concerns and negative public perception regarding us and our industry could adversely affect our business operations and the price of our common stock, debt securities and preferred stock.

Businesses across all industries are facing increasing scrutiny from investors, governmental authorities, regulatory agencies and the public related to their ESG practices, including practices and disclosures related to climate change, sustainability, diversity, equity and inclusion initiatives, and heightened governance standards. Failure, or a perceived failure, to adequately respond to or meet evolving investor, stockholder or public ESG expectations, concerns and standards may cause a business entity to suffer reputational damage and materially and adversely affect the entity's business, financial condition, or stock and debt prices. In addition, organizations that provide ESG information to investors have developed ratings processes for evaluating a business entity's approach to ESG matters. Although currently no universal rating standards exist, the importance of sustainability evaluations is becoming more broadly accepted by investors and stockholders, with some using these ratings to inform investment and voting decisions. Additionally, certain investors use these scores to benchmark businesses against their peers and, if a business entity is perceived as lagging, these investors may engage with the entity to demand improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a business entity's sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of our securities from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of our operations by certain investors. In addition, efforts in recent years aimed at the investment community to generally promote the divestment of fossil fuel equities and to limit or curtail activities with companies engaged in the extraction of fossil fuel reserves could limit our ability to access capital markets. These initiatives by activists and banks, including certain banks who are parties to the credit agreement providing for our revolving credit agreement, could interfere with our business activities, operations and ability to access capital.

Further, negative public perception regarding us and our industry resulting from, among other things, concerns raised by advocacy groups about climate change impacts of methane and other greenhouse gas emissions, hydraulic fracturing, oil spills, and pipeline explosions coupled with increasing societal expectations on businesses to address climate change and potential consumer use of substitutes to carbon-intensive energy commodities may result in increased costs, reduced demand for our oil, natural gas and NGL production, reduced profits, increased regulation, regulatory investigations and litigation, and negative impacts on our stock and debt prices and access to capital markets. These factors could also cause the permits we need to conduct our operations to be challenged, withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Federal, state and local laws and regulations, judicial actions and regulatory initiatives related to oil and gas development and the use of hydraulic fracturing could result in increased costs and operating restrictions or delays and adversely affect our business, financial condition, results of operations and cash flows.

Our operations are subject to extensive federal, state and local laws and regulations, including drilling and environmental and safety laws and regulations, which increase the cost of planning, designing, drilling, installing and operating oil and natural gas facilities. New laws and regulations or revisions or reinterpretations of existing laws and regulations could further increase these costs, could increase our liability risks, and could result in increased restrictions on oil and gas exploration and production activities, which could have a material adverse effect on us and the oil and gas industry as a whole. Risk of substantial costs and liabilities related to environmental and safety matters in particular, including compliance issues, environmental contamination and claims for damages to persons or property, are inherent in oil and natural gas operations. Failure to comply with applicable environmental and safety laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action requirements and orders. In addition, applicable laws and regulations require us to obtain many permits for the operation of various facilities. The issuance of required permits is not guaranteed and, once issued, permits are subject to revocation, modification and renewal. Failure to comply with applicable laws and regulations can result in fines and penalties or require us to incur substantial costs to remedy violations.

For additional information, please read “Business and Properties—Other Business Matters—Regulation of Oil and Natural Gas Exploration and Production,” “—Regulation of Natural Gas Marketing, Gathering and Transportation,” and “—Environmental and Safety Regulations” in Items 1 and 2.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Our ability to produce oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Water is an essential component of oil and natural gas production during the drilling process. In particular, we use a significant amount of water in the hydraulic fracturing process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

For additional information, please read “Business and Properties—Other Business Matters—Environmental and Safety Regulations—Clean Water Act” in Items 1 and 2.

The adoption of climate change legislation or regulations restricting emission of greenhouse gases could result in increased operating costs and reduced demand for the oil and gas we produce.

Studies have found that emission of certain gases, commonly referred to as GHGs impact the earth's climate. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict GHG emissions. These actions as well as any future laws or regulations that regulate or limit GHG emissions from our equipment and operations could require us to develop and implement new practices aimed at reducing GHG emissions, such as emissions control technologies, and to monitor and report GHG emissions associated with our operations, any of which could increase our operating costs and could adversely affect demand for the oil and gas that we produce. At this time, it is not possible to quantify the impact of such future laws and regulations on our business.

For additional information, please read "Business and Properties—Other Business Matters—Environmental and Safety Regulations—Greenhouse Gas and Climate Change Laws and Regulations" in Items 1 and 2.

We are subject to various climate-related risks.

The following is a summary of potential climate-related risks that could adversely affect us:

Transition Risks. Transition risks are related to the transition to a lower-carbon economy and include policy and legal, technology, and market risks.

Policy and Legal Risks. Policy risks include actions that seek to lessen activities that contribute to adverse effects of climate change or to promote adaptation to climate change. Examples of policy actions that would increase the costs of our operations or lower demand for our oil and gas include implementing carbon-pricing mechanisms, shifting energy use toward lower emission sources, adopting energy-efficiency solutions, encouraging greater water efficiency measures, and promoting more sustainable land-use practices. Policy actions also may include restrictions or bans on oil and gas activities, which could lead to write-downs or impairments of our assets or may incentivize the use of alternative or renewable sources of energy that could reduce the demand for our products. For example, the IRA contains tax inducements and other provisions that incentivize investment, development and deployment of alternative energy sources and technologies, and at COP28 in December 2023, more than 190 governments reached a non-binding agreement to transition away from fossil fuels and encourage the growth and expansion of renewable energy. Legal risks include potential lawsuits or regulations regarding the impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks. For example, the SEC in 2022 proposed rules on climate change disclosure requirements for public companies which, if adopted as proposed, could result in substantial compliance costs, and in September of 2023, California passed climate-related disclosure mandates that are broader than the SEC's proposed rules.

Furthermore, we could also face an increased risk of climate-related litigation or "greenwashing" suits with respect to our operations, disclosures, or products. Claims have been made against certain energy companies alleging that GHG emissions from oil, gas and NGL operations constitute a public nuisance under federal and state law. Private individuals or public entities also could attempt to enforce environmental laws and regulations against us and could seek personal injury and property damages or other remedies. Additionally, governments and private parties are also increasingly filing suits, or initiating regulatory action, based on allegations that certain public statements regarding ESG-related matters by companies are false and misleading “greenwashing” campaigns that violate deceptive trade practices and consumer protection statutes or that climate-related disclosures made by companies are inadequate. Similar issues can also arise when aspirational statements such as net-zero or carbon neutrality targets are made without clear plans. Although we are not a party to any such climate-related or “greenwashing” litigation currently, unfavorable rulings against us in any such case brought against us in the future could significantly impact our operations and could have an adverse impact on our financial condition.

Technology Risks. Technological improvements or innovations that support the transition to a lower-carbon, more energy efficient economic system may have a significant impact on us. The development and use of emerging technologies in renewable energy, battery storage, and energy efficiency may lower demand for oil and gas, resulting in lower prices and revenues, and higher costs. In addition, many automobile manufacturers have announced plans to shift production from internal combustion engine to electric powered vehicles, and states and foreign countries have announced bans on sales of internal combustion engine vehicles beginning as early as 2025, which would reduce demand for oil.

Market Risks. Markets could be affected by climate change through shifts in supply and demand for certain commodities, especially carbon-intensive commodities such as oil and gas and other products dependent on oil and gas. Lower demand for our oil and gas production could result in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to less carbon-intensive industries and alternative energy industries. In addition, investment advisers, banks, and certain sovereign wealth, pension, and endowment funds recently have been promoting divestment of investments in fossil fuel companies and pressuring lenders to limit funding to companies engaged in the extraction, production, and sale of oil and gas. For additional information, please read “—Risks Related to our Indebtedness, Hedging Activities and Financial Position—We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all” in this Item 1A.

Reputation Risk. Climate change is a potential source of reputational risk, which is tied to changing customer or community perceptions of an organization’s contribution to, or detraction from, the transition to a lower-carbon economy. For additional information, please read “—ESG concerns and negative public perception regarding us and our industry could adversely affect our business operations and the price of our common stock, debt securities and preferred stock.” in this Item 1A.

Physical Risks. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, floods or freezes) or may be driven by longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts, such as supply chain disruption, changes in water availability, sourcing, and quality, which could impact drilling and completion operations. These physical risks could cause increased costs, production disruptions, lower revenues and substantially increase the cost or limit the availability of insurance.

We are subject to a number of privacy and data protection laws, rules and directives (collectively, “data protection laws”) relating to the processing of personal data.

The regulatory environment surrounding data protection laws is uncertain. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. A determination that there have been violations of applicable data protection laws could expose us to significant damage awards, fines and other penalties that could materially harm our business and reputation.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance and adversely affect our business. As noted above, we are also subject to the possibility of security and privacy breaches, which themselves may result in a violation of these laws. Additionally, the acquisition of a company that is not in compliance with applicable data protection laws may result in a violation of these laws.

Tax law changes could have an adverse effect on our financial position, results of operations and cash flows.

Periodically U.S. legislators propose substantive changes to existing federal income tax laws that would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. Past proposals have included repeal of the percentage depletion allowance for oil and gas properties; elimination of the ability to fully deduct intangible drilling costs in the year incurred; and increase in the geological and geophysical amortization period for independent producers. These proposals have also included general tax law changes to raise tax rates on both domestic and foreign income.

Should the U.S. or the states pass tax legislation limiting any currently allowed tax incentives and deductions, our taxes would increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since future changes to federal and state tax legislation and regulations are unknown, we cannot predict the ultimate impact such changes may have on our business.

Risks Related to our Corporate Structure

Provisions of Delaware law and our bylaws and charter could discourage change-in-control transactions and prevent stockholders from receiving a premium on their investment.

Our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit the calling of a special meeting by our stockholders and place procedural requirements and limitations on stockholder proposals at meetings of stockholders. Because of these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our charter.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our charter limits the liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the Company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

The exclusive-forum provision contained in our bylaws could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our bylaws provide that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (1) any derivative action or proceeding brought on behalf of us, (2) any action asserting a claim of breach of a fiduciary duty owed by any current or former director, officer, other employee or agent of Coterra to Coterra or our stockholders, including a claim alleging the aiding and abetting of such a breach of fiduciary duty, (3) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law or our bylaws or charter or (4) any action asserting a claim governed by the internal affairs doctrine or asserting an "internal corporate claim" shall, to the fullest extent permitted by law, be the Court of Chancery of the State of Delaware (or, if the Court of Chancery does not have jurisdiction, the U.S. federal district court for the District of Delaware).

To the fullest extent permitted by applicable law, this exclusive-forum provision applies to state and federal law claims, including claims under the federal securities laws, including the Securities Act of 1933, as amended (the "Securities Act"), and the Securities Exchange Act of 1934, as amended (the "Exchange Act"), although our stockholders will not be deemed to have waived our compliance with the federal securities laws and the rules and regulations thereunder. This exclusive-forum provision may limit the ability of a stockholder to bring a claim in a judicial forum of its choosing for disputes with us or our directors, officers or other employees, which may discourage lawsuits against us and our directors, officers and other employees. Alternatively, if a court were to find this exclusive-forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings described above, we may incur additional costs associated with resolving such matters in other jurisdictions, which could negatively affect our business, results of operations and financial condition. In addition, stockholders who do bring a claim in a state or federal court located within the State of Delaware could face additional litigation costs in pursuing any such claim, particularly if they do not reside in or near Delaware. In addition, the court located in the State of Delaware may reach different judgments or results than would other courts, including courts where a stockholder would otherwise choose to bring the action, and such judgments or results may be more favorable to us than to our stockholders.

General Risk Factors

The loss of key personnel could adversely affect our ability to operate.

Our operations depend on a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense and can be exacerbated following a downturn in which talented professionals leave the industry or when potential new entrants to the industry decide not to undertake the professional training to enter the industry. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the oil and natural gas industry is intense. Major and independent oil and natural gas companies actively bid for desirable oil and gas properties, as well as for the capital, equipment, labor and infrastructure required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe will be increasingly important to attaining success in the industry. These companies may also have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of current and future governmental regulations and taxation.

Further, certain of our competitors may engage in bankruptcy proceedings, debt refinancing transactions, management changes or other strategic initiatives in an attempt to reduce operating costs to maintain a position in the market. This could result in such competitors emerging with stronger or healthier balance sheets and in turn an improved ability to compete with us in the future. We have seen and may continue to see corporate consolidations among our competitors, which could significantly alter industry conditions and competition within the industry.

Because our activity is concentrated in areas of heavy industry competition, there is heightened demand for equipment, power, services, facilities and resources, resulting in higher costs than in other areas. Such intense competition also could result in delays in securing, or the inability to secure, the equipment, power, services, water or other resources or facilities necessary for our development activities, which could negatively impact our production volumes. In remote areas, vendors also can charge higher rates due to the inability to attract employees to those areas and the vendors' ability to deploy their resources in easier-to-access areas.

The declaration, payment and amounts of future dividends distributed to our stockholders and the repurchase of our common stock will be uncertain.

Although we have paid cash dividends on shares of our common stock and have conducted repurchases of our common stock in the past, our Board of Directors may determine not to take such actions in the future or may reduce the amount of dividends or repurchases made in the future. Decisions on whether, when and in which amounts to declare and pay any future dividends, or to authorize and make any repurchases of our common stock, will remain in the discretion of our Board of Directors. We expect that any such decisions will depend on our financial condition, results of operations, cash balances, cash requirements, future prospects, the outlook for commodity prices and other considerations that our Board of Directors deems relevant.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Governance

Our Board of Directors, with assistance from our Audit Committee, oversees our risk management program, which includes technology and cybersecurity risks. Our management team, including our Vice President - Information Technology ("VP - IT"), provides periodic updates on risk management to the Audit Committee and to the Board of Directors. Such periodic updates include presentations regarding cybersecurity matters, including any new cybersecurity threats, events, incidents, risks, risk management solutions, trainings or education, strategy pivots, or governance changes. The Audit Committee regularly reports its actions, findings and recommendations to the Board of Directors. The Audit Committee relies in large part on such periodic updates and presentations from our management team in developing its reports to the Board of Directors.

Risk Management and Strategy

We maintain a cybersecurity Incident Response Plan ("IRP") designed to identify, assess, manage, mitigate, and respond to cybersecurity risks, threats and incidents. The IRP was developed in consultation with common cybersecurity frameworks, including NIST Cybersecurity Framework, to provide efficiency, familiarity and consistency in design. As part of our IRP, we have established a Cybersecurity Incident Management Team ("CIMT"), comprised of senior level executives and management, that defines overall policy and strategy when faced with a cybersecurity incident. The CIMT provides cross-functional and geographical visibility, as well as executive leadership oversight, to address and mitigate associated risks. Among our CIMT, our VP - IT holds the highest level of executive responsibility for assessing and managing cybersecurity threats, incidents, and risks, as well as developing and implementing all cybersecurity risk management, strategy, and governance recommendations. Our VP - IT leads all components of our information technology functions and reports to our Executive Vice President and Chief Financial Officer.

The CIMT is supported by a dedicated Cybersecurity Incident Response Team (“CIRT”), comprised generally of security and networking team members with responsibilities to monitor and assess events, cybersecurity incidents, and technical activities throughout our organization. Our CIRT members possess critical skill sets, experience, and competencies related to the management of cybersecurity risks and matters. In particular, our VP - IT has over 28 years of experience in the field of information systems and cybersecurity and leads an experienced security and networking team with 67 years of additional combined experience in developing and executing cybersecurity strategies. Our CIRT members also hold over 29 certifications in risk and information security from organizations such as International Information System Security Certification Consortium (ISC2), The SANS Institute, Global Information Assurance Certification (GIAC), CompTIA and Cisco, including Certified Information Systems Security Professional (CISSP), GIAC, Certified Incident Handler Certification (GCIH), GIAC Critical Controls Certification (GCCC), GIAC Continuous Monitoring Certification (GMON), SANS Security Awareness Professional (SSAP), Certified Information Security Manager (CISM), Certified in Risk and Information Systems Control (CRISC), and Certified Information Systems Auditor (CISA).

Our CIRT is supported by dedicated Information Technology (“IT”) and Operational Technology (“OT”) security resources, and further supported by various external parties, including but not limited to, cybersecurity service providers, assessors, consultants, auditors, and other third parties engaged on an as-needed basis.

The CIRT determines whether a cybersecurity incident warrants escalation to the CIMT. In the event of a cybersecurity incident, the IRP describes processes to detect, analyze, contain, eradicate and remediate such incident. These processes include, but are not limited to:

- Maintaining an updated inventory and management of digital assets;
- Conducting risk assessments to validate our cybersecurity policies, practices, and tools;
- Employing appropriate next generation firewalls, endpoint detection and response (EDR) software, identity and access management (IAM), multifactor authentication (MFA), virtual private network (VPN), account change monitoring, encryption, patch management, web content filter, spam filter and reporting, and security information and event management (SIEM) software;
- Conducting regular vulnerability scans of our IT and OT infrastructure;
- Obtaining and applying vulnerability patches appropriately;
- Conducting penetration tests and assessing recommended corrective actions;

- Requiring employees to complete a security awareness training program;
- Conducting regular phishing simulations and tabletop exercises to test familiarity with cybersecurity policies and procedures; and
- Reviewing and evaluating developments in the cyber threat landscape.

Our IRP also describes processes to identify material risks from cybersecurity incidents associated with our use of third-party service providers.

Currently, we are not aware of any material risks from cybersecurity threats that have materially affected or are reasonably likely to materially affect our operations. However, the nature of potential cybersecurity risks and threats are uncertain, and any future incidents, outages or breaches could have a material adverse effect on our reputation, business strategy, results of operations or financial condition.

ITEM 3. LEGAL PROCEEDINGS

Legal Matters

We are involved in various legal proceedings incidental to our business. The information set forth under the heading “Legal Matters” in Note 8 of the Notes to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

Governmental Proceedings

From time to time we receive notices of violation from governmental and regulatory authorities, including notices 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, penalties or both, if fines or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $300,000.

In June 2023, we received a Notice of Violation and Opportunity to Confer (“NOVOC”) from the U.S. EPA alleging violations of the Clean Air Act, the Texas State Implementation Plan, the New Mexico State Implementation Plan (“NMSIP”) and certain other state and federal regulations pertaining to facilities in Texas and New Mexico. Separately, in July 2023, we received a letter from the U.S. Department of Justice that the EPA has referred this NOVOC for civil enforcement proceedings. In August 2023, we received a second NOVOC from the EPA alleging violations of the Clean Air Act, the NMSIP, and certain other state and federal regulations pertaining to facilities in New Mexico. We have exchanged information with the EPA and continue to engage in discussions aimed at resolving the allegations. At this time we are unable to predict with certainty the financial impact of these NOVOCs or the timing of any resolution. However, any enforcement action related to these NOVOCs will likely result in fines or penalties, or both, and corrective actions, which may increase our development costs or operating costs. We believe that any fines, penalties, or corrective actions that may result from this matter will not have a material effect on our financial position, results of operations, or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following table shows certain information as of February 23, 2024 about our executive officers, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934. All officers are elected annually by our Board of Directors.

Name	Age	Position
Thomas E. Jorden	66	Chairman, Chief Executive Officer and President
Shannon E. Young III	52	Executive Vice President and Chief Financial Officer
Stephen P. Bell	69	Executive Vice President, Business Development
Andrea M. Alexander	42	Senior Vice President and Chief Human Resources Officer
Blake Sirgo	41	Senior Vice President, Operations
Adam Vela	50	Senior Vice President and General Counsel
Michael D. DeShazer	38	Vice President of Business Units
Gary Hlavinka	62	Vice President, Marcellus Business Unit
Todd M. Roemer	53	Vice President and Chief Accounting Officer
Kevin W. Smith	38	Vice President and Chief Technology Officer

Mr. Jorden was appointed Chief Executive Officer and President of Coterra following the Merger with Cimarex in October 2021 and Chairman of the Board of Coterra in November 2022. Mr. Jorden previously served as the Chief Executive Officer and President of Cimarex beginning September 2011 and as Chairman of the Board of Directors of Cimarex beginning August 2012. At Cimarex, he began serving as Executive Vice President of Exploration when the company formed in 2002. Prior to the formation of Cimarex, Mr. Jorden held multiple leadership roles at Key Production Company, Inc. (“Key”), which was acquired by Cimarex in 2002. He joined Key in 1993 as Chief Geophysicist and subsequently became Executive Vice President of Exploration. Before joining Key, Mr. Jorden served at Union Pacific Resources and Superior Oil Company.

Mr. Young was appointed Executive Vice President and Chief Financial Officer in July 2023. From 2019 to 2023, Mr. Young served as Executive Vice President and Chief Financial Officer of Talos Energy Inc. Prior to joining Talos Energy Inc., Mr. Young served in similar positions with Sheridan Production Company, LLC, Cobalt International Energy, Inc. and Talos Energy LLC. Mr. Young served as a Managing Director for the Global Energy Group at Goldman, Sachs & Co. from 2010 to 2014 and was an investment banker at Morgan Stanley from 1998 to 2010.

Mr. Bell was appointed Executive Vice President of Business Development following the Merger with Cimarex in October 2021. At Cimarex, Mr. Bell was appointed Senior Vice President of Business Development and Land in September 2002 and was named Executive Vice President of Business Development in September 2012. Mr. Bell served at Key prior to its acquisition by Cimarex. He joined Key in 1994 as Vice President of Land and was appointed Senior Vice President of Business Development and Land in 1999.

Ms. Alexander was appointed Senior Vice President and Chief Human Resources Officer in July 2023. Ms. Alexander served as Chief People Officer at Rent the Runway from June 2021 to July 2023. Ms. Alexander served in various roles of increasing responsibility, including Associate Partner and Professional Development Manager, at McKinsey & Company, a management consulting company, from 2009 to 2021.

Mr. Sirgo was appointed Senior Vice President of Operations in October 2022. Mr. Sirgo previously served as Vice President of Operations at Coterra from October 1, 2021 to October 1, 2022. Prior to the Merger with Cimarex in October 2021, Mr. Sirgo served in a number of technical and leadership roles since joining Cimarex in 2008, including Vice President of Operations from February 2020 to October 2021, Vice President of Operation Resources from November 2018 to February 2020, Permian Division Production Manager from June 2016 to November 2018, and in various engineering and production manager positions. Before joining Cimarex, Mr. Sirgo worked at Occidental Petroleum.

Mr. Vela was appointed Vice President and General Counsel in October 2022 and was promoted to Senior Vice President and General Counsel in August 2023. Mr. Vela previously served in various capacities at Coterra and Cimarex beginning in 2005, including Vice President, Assistant General Counsel, Chief Litigation Counsel and Corporate Counsel. Mr. Vela is a member of the Texas, Colorado, American and Houston Hispanic Bar associations, as well as the Foundation for Natural Resources and Energy Law.

Mr. DeShazer was appointed Vice President of Business Units following the Merger with Cimarex in October 2021. Mr. DeShazer joined Cimarex in 2007, serving in various engineering and reservoir manager positions, as well as multiple leadership roles, including Technology Group Manager from 2016 to 2018, Asset Evaluation Team Manager from 2018 to 2019 and Vice President of the Permian Business Unit in 2019.

Mr. Hlavinka was appointed Vice President of the Marcellus Business Unit in April 2022. Since joining Coterra, formerly Cabot Oil & Gas Corporation, in 1989, he has served in engineering and management roles across the Company’s operations, in multiple producing basins. Mr. Hlavinka worked initially as a Facility Engineer and District Superintendent in the Company’s West Virginia production operations, and subsequently as a Corporate Reservoir Engineer in Houston, Texas. In 2006 he was named West Region Engineering Manager for the Rocky Mountain and Mid-Continent operating areas, and in 2009 he was promoted to Regional Operations Manager for the North Region, with responsibility for Appalachian Basin operations and engineering.

Mr. Roemer was appointed Vice President and Chief Accounting Officer in July 2019. Mr. Roemer previously served as Vice President and Controller from February 2017 to July 2019 and Controller from March 2010 to February 2017. Prior to joining Coterra in 2010, Mr. Roemer was a Senior Manager in the energy practice of PricewaterhouseCoopers LLP. Mr. Roemer is a Certified Public Accountant in the state of Texas.

Mr. Smith was appointed Vice President and Chief Technology Officer following the Merger with Cimarex in October 2021. Mr. Smith began his career with Cimarex in 2007, serving in a number of technical and leadership roles, including Director of Technology and Anadarko Exploration Region Manager. In September 2020, Mr. Smith assumed the role of Chief Engineer for Cimarex.

PART II

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

Our $0.10 par value common stock is listed and principally traded on the NYSE under the ticker symbol “CTRA.” Cash dividends were paid to our common stockholders in each quarter of 2023. Future dividend payments will depend on the Company's level of earnings, financial requirements and other factors considered relevant by our Board of Directors.

As of February 6, 2024, there were 858 registered holders of our common stock.

ISSUER PURCHASES OF EQUITY SECURITIES

In February 2023, our Board of Directors terminated the previously authorized share repurchase plan and approved a new share repurchase program that authorizes us to purchase up to $2.0 billion of our common stock in the open market or in negotiated transactions. During the quarter ended December 31, 2023, we purchased 1 million shares of common stock for $29 million, bringing our total repurchases in 2023 to 17 million shares of common stock at a total cost of $418 million. As of December 31, 2023, we were authorized to repurchase up to approximately an additional $1.6 billion of our outstanding common stock.

The following table sets forth information regarding repurchases of our common stock during the quarter ended December 31, 2023.

Period [(1)]	Total Number of Shares Purchased (In thousands)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (In thousands)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (In millions)
October 2023	430	$ 26.90	430	$ 1,603
November 2023	307	$ 27.47	307	$ 1,595
December 2023[(2)]	333	$ 26.14	333	$ 1,586
Total	1,070		1,070	

(1) All purchases during the covered periods were made under the new share repurchase program, which was approved by our Board of Directors in February 2023 and which authorized the repurchase of up to $2.0 billion of our common stock. The new share repurchase program does not have an expiration date.

(2) In December 2023, we purchased 332,634 shares of common stock delivered to us by employees to satisfy withholding taxes on the vesting of restricted stock awards.

ITEM 6. [RESERVED]

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

The following discussion and analysis are based on management's perspective and are intended to assist you in understanding our results of operations and our present financial condition and outlook. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Annual Report on Form 10-K contain additional information that should be referenced when reviewing this material. This discussion and analysis also include forward-looking statements. Readers are cautioned that such forward-looking statements are based on current expectations and assumptions that involve a number of risks and uncertainties, including those described under "Forward-Looking Statements" in Part I of this report and "Risk Factors" in Part I, Item 1A of this report, which could cause actual results to differ materially from those included in this report.

OVERVIEW

Financial and Operating Overview

Financial and operating results for the year ended December 31, 2023 compared to the year ended December 31, 2022 are as follows:

- Net income decreased $2.4 billion from $4.1 billion, or $5.09 per share, in 2022 to $1.6 billion, or $2.14 per share, in 2023.
- Net cash provided by operating activities decreased $1.8 billion, from $5.5 billion, in 2022 to $3.7 billion in 2023.
- Equivalent production increased 12.2 MMBoe from 231.3 MMBoe, or 633.8 MBoe per day, in 2022 to 243.5 MMBoe, or 667.1 MBoe per day, in 2023.
  - Natural gas production increased 28.4 Bcf from 1,024.3 Bcf, or 2,806 MMcf per day, in 2022 to 1,052.7 Bcf, or 2,884 MMcf per day, in 2023.
  - Oil production increased 3.2 MMBbl from 31.9 MMBbl, or 87 MBbl per day, in 2022 to 35.1 MMBbl, or 96 MBbl per day, in 2023.
  - NGL volumes increased 4.2 MMBbl from 28.7 MMBbl, or 79 MBbl per day, in 2022 to 32.9 MMBbl, or 90 MBbl per day, in 2023.
- Average realized prices:
  - Natural gas was $2.44 per Mcf in 2023, 50 percent lower than the $4.91 per Mcf price realized in 2022.
  - Oil was $76.07 per Bbl in 2023, 10 percent lower than the $84.33 per Bbl price realized in 2022.
  - NGL price for 2023 was $19.56 per Bbl, 42 percent lower than the $33.58 per Bbl price realized in 2022.
- Total capital expenditures for drilling, completion and other fixed assets were $2.1 billion in 2023 compared to $1.7 billion in 2022. The increase was driven by higher planned completion activity levels across our operations and higher costs.
- Increased our quarterly base dividend from $0.15 per share for regular quarterly dividends in 2022 to $0.20 per share in 2023 as part of our returns-focused strategy.
- Increased our quarterly base dividend from $0.20 per share to $0.21 per share in February 2024.
- Implemented our new $2.0 billion share repurchase program and repurchased 17 million shares for $418 million during the year ended December 31, 2023. Under our previous share repurchase program, we repurchased 48 million shares for $1.25 billion during the year ended December 31, 2022.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly commodity prices and our ability to find, develop and market our production on economically attractive terms.

Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by pipeline capacity constraints, inventory storage levels, basis differentials, weather conditions, and geopolitical, economic and other factors.

Oil prices have recovered in recent years from previous pandemic related market weakness, particularly on the demand side. Global conflict and supply chain disruptions drove high oil prices in 2022, which then moderated throughout 2023. OPEC+ reacted with supply reductions, helping to stabilize oil price levels during 2023. Oil and gas companies in the U.S. have largely refrained from expanding their existing production, which has contributed to steadier oil prices in 2023 as compared to recent years and to improved oil futures prices in early 2024.

Natural gas prices trended down year-over-year but strengthened in fourth quarter due to increased power demand. However, natural gas futures prices have declined in the first part of 2024 as the domestic market appears oversupplied.

Although the current outlook on oil and natural gas prices is generally favorable and our operations have not been significantly impacted in the short-term, in the event further disruptions occur and continue for an extended period of time, our operations could be adversely impacted, commodity prices could decline and our costs may increase. Oil and natural gas prices have fallen significantly since their peak in 2022, and we expect commodity price volatility to continue driven by further geopolitical disruptions, including conflicts in the Middle East and actions of OPEC+, and swift near and medium term fluctuations in supply and demand. Although we are unable to predict future commodity prices, at current oil, natural gas and NGL price levels, we do not believe that an impairment of our oil and gas properties is reasonably likely to occur in the near future. However, in the event that commodity prices significantly decline or costs increase significantly from current levels, our management would evaluate the recoverability of the carrying value of our oil and gas properties.

In addition, the issue of, and increasing political and social attention on, climate change has resulted in both existing and pending national, regional and local legislation and regulatory measures, such as mandates for renewable energy and emissions reductions targeted at limiting or reducing emissions of GHGs. Changes in these laws or regulations may result in delays or restrictions in permitting and the development of projects, may result in increased costs and may impair our ability to move forward with our construction, completions, drilling, water management, waste handling, storage, transport and remediation activities, any of which could have an adverse effect on our financial results.

For information about the impact of realized commodity prices on our revenues, refer to "Results of Operations" below.

FINANCIAL CONDITION

Liquidity and Capital Resources

We strive to maintain an adequate liquidity level to address commodity price volatility and risk. Our liquidity requirements consist primarily of our planned capital expenditures, payment of contractual obligations (including debt maturities and interest payments), working capital requirements, dividend payments and share repurchases. Although we have no obligation to do so, we may also from time-to-time refinance or retire our outstanding debt through privately negotiated transactions, open market repurchases, redemptions, exchanges, tender offers or otherwise.

Our primary sources of liquidity are cash on hand, net cash provided by operating activities and available borrowing capacity under our revolving credit agreement. Our liquidity requirements are generally funded with cash flows provided by operating activities, together with cash on hand. However, from time to time, our investments may be funded by bank borrowings (including draws under our revolving credit agreement), sales of non-strategic assets, and private or public financing based on our monitoring of capital markets and our balance sheet. Our debt is currently rated as investment grade by the three leading rating agencies, and there are no "rating triggers" in any of our debt agreements that would accelerate the scheduled maturities should our debt rating fall below a certain level. In determining our debt ratings, the agencies consider a number of qualitative and quantitative items including, but not limited to, current commodity prices, our liquidity position, our debt levels and leverage ratios, the size and mix of our production and proved reserves, and our cost structure. Credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. A change in our debt rating could impact our interest rate on any borrowings under our revolving credit agreement and our ability to economically access debt markets in the future and could trigger the requirement to post credit support under various agreements, which could reduce the borrowing capacity under our revolving credit agreement. We believe that, with operating cash flow, cash on hand and availability under our revolving credit agreement, we have the ability to finance our spending plans over the next twelve months and, based on current expectations, for the longer term.

Our working capital is substantially influenced by the variables discussed above and fluctuates based on the timing and amount of borrowings and repayments under our revolving credit agreement, repayments of debt, the timing of cash collections and payments on our trade accounts receivable and payable, respectively, payment of dividends, repurchases of our securities and changes in the fair value of our commodity derivative activity. From time to time, our working capital will reflect a deficit, while at other times it will reflect a surplus. This fluctuation is not unusual. At December 31, 2023 and 2022, we had a working capital surplus of $355 million and $1.0 billion, respectively. The decrease in our working capital surplus is primarily due to the reclassification during 2023 of $575 million of long-term debt scheduled to mature in September 2024 to current liabilities. We believe we have adequate liquidity and availability under our revolving credit agreement as outlined above to meet our working capital requirements over the next 12 months.

As of December 31, 2023, we had no borrowings outstanding under our revolving credit agreement, our unused commitments were $1.5 billion, and we had unrestricted cash on hand of $956 million.

Cash Flows

Our cash flows from operating activities, investing activities and financing activities are as follows:

	Year Ended December 31,		
(In millions)	**2023**	**2022**	**2021**
Cash flows provided by operating activities	$ 3,658	$ 5,456	$ 1,667
Cash flows (used in) provided by investing activities	(2,059)	(1,674)	313
Cash flows used in financing activities	(1,317)	(4,145)	(1,086)

Operating Activities. Operating cash flow fluctuations are substantially driven by changes in commodity prices, production volumes and operating expenses. Commodity prices have historically been volatile, primarily as a result of supply and demand for oil and natural gas, pipeline infrastructure constraints, basis differentials, inventory storage levels, seasonal influences and geopolitical, economic and other factors. In addition, fluctuations in cash flow may result in an increase or decrease in our capital expenditures.

Net cash provided by operating activities in 2023 decreased by $1.8 billion compared to 2022. This decrease was primarily due to lower net income as a result of lower natural gas, oil and NGL revenue due to lower commodity prices, partially offset by higher production. This decrease was partially offset by lower operating costs, higher cash received on derivative settlements and a larger contribution from changes in working capital and other assets and liabilities.

Refer to “Results of Operations” for additional information relative to commodity price, production and operating expense fluctuations. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

Investing Activities. Cash flows used in investing activities increased by $385 million from 2022 to 2023. The increase was primarily due to $389 million of higher capital expenditures due to our increased capital budget for 2023 compared to 2022 .

Financing Activities. Cash flows used in financing activities decreased by $2.8 billion from 2022 to 2023. The decrease was primarily due to $1.1 billion of lower dividend payments and $845 million of lower common stock repurchases during 2023, and $874 million net repayments of debt in 2022.

2022 and 2021 Compared. For information on the comparison of operating, investing, and financing cash flows for the year ended December 31, 2022 compared to the year ended December 31, 2021, refer to Financial Condition (Cash Flows) included in the Coterra Energy Inc. Annual Report on Form 10-K for the year ended December 31, 2022, which information in incorporated by reference herein.

Revolving Credit Agreement

We had $1.5 billion of borrowing capacity under our revolving credit agreement at December 31, 2023. The revolving credit agreement is scheduled to mature in March 2028 and can be extended for additional one-year periods on up to two occasions upon the agreement of lenders holding at least 50 percent of the commitments under the credit agreement and us. Borrowings under our revolving credit agreement bear interest at a rate per annum equal to, at our option, (i) either a term secured overnight financing rate ("SOFR") plus a 0.10 percent credit spread adjustment for all tenors or (ii) a base rate, in each case plus an interest rate margin which ranges from 0 to 75 basis points for base rate loans and 100 to 175 basis points for term SOFR loans based on our credit rating. Our revolving credit agreement includes certain customary covenants, including the maintenance of a maximum leverage ratio of no more than 3.0 to 1.0 as of the last day of any fiscal quarter. At such time as we have no other debt in a principal amount in excess of $75 million outstanding that has a financial maintenance covenant based on a substantially similar leverage ratio, in lieu of such maximum leverage ratio covenant, the revolving credit agreement will instead require us to maintain a ratio of total debt to total capitalization of no more than 65 percent. At December 31, 2023, we were in compliance with all financial covenants for our revolving credit agreement. Refer to Note 4 of the Notes to the Consolidated Financial Statements, "Long-Term Debt and Credit Agreements," for further details regarding the interest rate on future borrowings under the revolving credit agreement and our leverage ratio.

Certain Restrictive Covenants

Our ability to incur debt, incur liens, enter into mergers, sell assets, enter into transactions with affiliates, and engage in certain other activities are subject to certain restrictive covenants in our various debt instruments. In addition, the senior note agreement governing various series of senior notes that were issued in a private placement (the "private placement senior notes") requires us to maintain a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of not less than 2.8 to 1.0 and requires us to maintain, as of the last day of any fiscal quarter, a maximum ratio of total debt to consolidated EBITDAX for the trailing four quarters of not more than 3.0 to 1.0. At December 31, 2023, we were in compliance with all financial covenants in our private placement senior notes. Refer to Note 4 of the Notes to the Consolidated Financial Statements, “Long-Term Debt and Credit Agreements,” for further details regarding the restrictive covenants contained in our various debt instruments.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in millions)	**2023**	**2022**
Total debt	$ 2,161	$ 2,181
Stockholders' equity	13,039	12,659
Total capitalization	$ 15,200	$ 14,840
Debt to total capitalization	14%	15%
Cash and cash equivalents	$ 956	$ 673

Share repurchases. In February 2023, our Board of Directors approved a new share repurchase program which authorizes the purchase of up to $2.0 billion of our common stock in the open market or in negotiated transactions.

During 2023, we repurchased and retired 17 million shares of our common stock for $418 million under our authorized share repurchase program. During 2022, the Company repurchased 48 million shares of common stock for $1.25 billion under the February 2022 share repurchase program. During the years ended December 31, 2023 and 2022, 332,634 and 320,236 shares of common stock, respectively, were recorded as treasury stock and retired related to common shares that were retained from vested restricted stock awards for withholding of taxes.

In December 2022, our Board of Directors authorized the retirement of our common stock held in treasury as of December 31, 2022 and provided that prospectively, share repurchases and shares withheld for the vesting of stock awards will be retired in the period in which they are repurchased or withheld. Accordingly, as of December 31, 2023 and 2022, there were no common shares held in Treasury Stock on the Consolidated Balance Sheet.

Dividends. In February 2023, our Board of Directors approved an increase in the base quarterly dividend from $0.15 per share to $0.20 per share.

The following table presents our dividends paid on our common stock for the year ended December 31, 2023 and 2022.

	Rate per share			
	Base	Variable	Total	Total Dividends Paid (In millions)
2023	$ 0.80	$ 0.37	$ 1.17	$ 895
2022	$ 0.60	$ 1.89	$ 2.49	$ 1,991

In February 2024, our Board of Directors approved an increase in our base quarterly dividend from $0.20 per share to $0.21 per share beginning in the first quarter of 2024, and approved a quarterly base dividend of $0.21 per share.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital expenditures, excluding any significant property acquisitions, with cash generated from operations and, if required, borrowings under our revolving credit agreement. We budget these expenditures based on our projected cash flows for the year.

The following table presents major components of our capital and exploration expenditures:

(In millions)	Year Ended December 31, 2023	2022	2021
Acquisitions[1] :			
Proved	$ —	$ —	$ 7,472
Unproved	—	—	5,381
Total	$ —	$ —	$ 12,853
Capital expenditures			
Drilling and completion	$ 1,979	$ 1,617	$ 688
Pipeline and gathering	91	56	9
Other	34	54	23
Capital expenditures for drilling, completion and other fixed asset additions	2,104	1,727	720
Capital expenditures for leasehold and property acquisitions	10	10	5
Exploration expenditures[2]	20	29	18
Total	$ 2,134	$ 1,766	$ 743

---

(1) These amounts represent the fair value of the proved and unproved properties recorded in the purchase price allocation with respect to the Merger. The purchase was funded through the issuance of our common stock.

(2) There were no exploratory dry hole costs in 2023, 2022 and 2021.

In 2023, we drilled 264 gross wells (169.4 net) and completed 288 gross wells (183.3 net), of which 98 gross wells (62.7 net) were drilled but uncompleted in prior years.

Our 2024 capital program is expected to be approximately $1.75 billion to $1.95 billion. We expect to turn-in-line 132 to 158 total net wells in 2024 across our three core operating areas. Approximately 60 percent of our drilling and completion capital will be invested in the Permian Basin, 23 percent in the Marcellus Shale and 17 percent in the Anadarko Basin (at the mid-point). The decrease in our year-over-year capital expenditures is primarily driven by lower planned spending in the Marcellus Shale, partially offset by modest increases in the Permian Basin and Anadarko Basin. We will continue to assess the commodity price environment and may increase or decrease our capital expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. As of December 31, 2023, our material contractual obligations include debt and related interest expense, gathering, processing and transportation agreements, lease obligations, operational agreements, drilling and completion obligations, derivative obligations and asset retirement obligations. Other joint owners in the properties operated by us could incur a portion of these costs. We expect that our sources of capital will be adequate to fund these obligations. Refer to the Notes to the Consolidated Financial Statements included in Item 8 of this Annual Report for further details.

We enter into arrangements that can give rise to material off-balance sheet obligations. As of December 31, 2023, the material off-balance sheet arrangements we had entered into included certain firm gathering, processing and transportation commitments and operating lease agreements with terms at commencement of less than 12 months for equipment used in our exploration and development activities. We have no other off-balance sheet debt or other similar unrecorded obligations.

RESULTS OF OPERATIONS

2023 and 2022 Compared

Operating Revenues

(In millions)	Year Ended December 31, 2023	Year Ended December 31, 2022	Variance Amount	Variance Percent
Natural gas	$ 2,292	$ 5,469	$ (3,177)	(58)%
Oil	2,667	3,016	(349)	(12)%
NGL	644	964	(320)	(33)%
Gain (loss) on derivative instruments	230	(463)	693	(150)%
Other	81	65	16	25 %
	$ 5,914	$ 9,051	$ (3,137)	(35)%

Production Revenues

Our production revenues are derived from sales of our oil, natural gas and NGL production. Increases or decreases in our revenues, profitability and future production growth are highly dependent on the commodity prices we receive, which we expect to fluctuate due to supply and demand factors, and the availability of transportation, seasonality and geopolitical, economic and other factors.

Natural Gas Revenues

	Year Ended December 31, 2023	Year Ended December 31, 2022	Variance Amount	Variance Percent	Increase (Decrease) (In millions)
Volume variance (Bcf)	1,052.7	1,024.3	28.4	3 %	$ 152
Price variance ($/Mcf)	$ 2.18	$ 5.34	$ (3.16)	(59)%	(3,329)
Total					$ (3,177)

Natural gas revenues decreased $3.2 billion primarily due to significantly lower natural gas prices, partially offset by higher production. The increase in production was related to higher production in the Marcellus Shale, Permian Basin and Anadarko Basin.

Oil Revenues

	Year Ended December 31, 2023	Year Ended December 31, 2022	Variance Amount	Variance Percent	Increase (Decrease) (In millions)
Volume variance (MMBbl)	35.1	31.9	3.2	10%	$ 302
Price variance ($/Bbl)	$ 75.97	$ 94.47	$ (18.50)	(20)%	(651)
Total					$ (349)

Oil revenues decreased $349 million primarily due to lower oil prices, offset by higher production mainly in the Permian Basin.

NGL Revenues

	Year Ended December 31,		Variance		
	2023	2022	Amount	Percent	Increase (Decrease) (In millions)
Volume variance (MMBbl)	32.9	28.7	4.2	15 %	$ 141
Price variance ($/Bbl)	$ 19.56	$ 33.58	$ (14.02)	(42)%	(461)
Total					$ (320)

NGL revenues decreased $320 million primarily due significantly lower NGL prices, partially offset by higher NGL volumes, particularly in the Permian Basin.

Gain (Loss) on Derivative Instruments

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly cash settlements (if any) of the derivative instruments. We have elected not to designate our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to our derivative instruments. Consequently, changes in the fair value of our derivative instruments and cash settlements are included as a component of operating revenues as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statement of cash flows.

The following table presents the components of “Gain (loss) on derivative instruments” for the years indicated:

	Year Ended December 31,	
(In millions)	**2023**	**2022**
Cash received (paid) on settlement of derivative instruments		
Gas contracts	$ 280	$ (438)
Oil contracts	4	(324)
Non-cash gain (loss) on derivative instruments		
Gas contracts	(72)	149
Oil contracts	18	150
	$ 230	$ (463)

Operating Costs and Expenses

Costs associated with producing oil and natural gas are substantial. Among other factors, some of these costs vary with commodity prices, some trend with volume and commodity mix, some are a function of the number of wells we own and operate, some depend on the prices charged by service companies, and some fluctuate based on a combination of the foregoing. Our costs for services, labor and supplies have remained high due to on-going demand for those items, and to a lesser extent rising inflation and supply chain disruptions, all of which affected the cost of our operations throughout 2022. During 2023, these costs have begun to stabilize.

The following table reflects our operating costs and expenses for the years indicated and a discussion of the operating costs and expenses follows.

(In millions, except per Boe)	Year Ended December 31,		Variance		Per Boe	
	2023	2022	Amount	Percent	2023	2022
Operating Expenses						
Direct operations	$ 562	$ 460	$ 102	22 %	$ 2.31	$ 1.99
Gathering, processing and transportation	975	955	20	2 %	4.00	4.13
Taxes other than income	283	366	(83)	(23)%	1.16	1.58
Exploration	20	29	(9)	(31)%	0.08	0.13
Depreciation, depletion and amortization	1,641	1,635	6	— %	6.74	7.07
General and administrative	291	396	(105)	(27)%	1.20	1.70
	$ 3,772	$ 3,841	$ (69)	(2)%		

Direct Operations

Direct operations generally consist of costs for labor, equipment, maintenance, saltwater disposal, compression, power, treating and miscellaneous other costs (collectively, “lease operating expense”). Direct operations also include well workover activity necessary to maintain production from existing wells.

Direct operations consisted of lease operating expense and workover expense as follows:

(In millions, except per Boe)	Year Ended December 31, 2023	Year Ended December 31, 2022	Variance	Per Boe 2023	Per Boe 2022
Direct Operations					
Lease operating expense	$ 472	$ 370	$ 102	$ 1.94	$ 1.60
Workover expense	90	90	—	0.37	0.39
	$ 562	$ 460	$ 102	$ 2.31	$ 1.99

Lease operating expense increased primarily due to higher production levels. Additionally, lease operating expense on a per Boe basis generally increased due to increasing costs of equipment and field services, which began to stabilize in late 2023, and higher contract labor and employee-related costs.

Gathering, Processing and Transportation

Gathering, processing and transportation costs principally consist of expenditures to treat and transport production downstream from the wellhead, including gathering, fuel, and compression and processing costs, the last of which are incurred to extract NGLs from the raw natural gas stream. Gathering costs also include costs associated with operating our gas gathering infrastructure, including operating and maintenance expenses. Costs vary by operating area and will fluctuate with increases or decreases in production volumes, contractual fees, and changes in fuel and compression costs.

Gathering, processing and transportation increased $20 million primarily due to higher production levels, partially offset by lower costs in the Permian Basin and Anadarko Basin due to lower gathering and transportation rates which were driven by lower commodity prices during 2023 compared to the same period in 2022.

Taxes Other Than Income

Taxes other than income consist of production (or severance) taxes, drilling impact fees, ad valorem taxes and other taxes. State and local taxing authorities assess these taxes, with production taxes being based on the volume or value of production, drilling impact fees being based on drilling activities and prevailing natural gas prices and ad valorem taxes being based on the value of properties.

The following table presents taxes other than income for the years indicated:

(In millions)	Year Ended December 31, 2023	2022	Variance
Taxes Other than Income			
Production	$ 205	$ 282	$ (77)
Drilling impact fees	23	31	(8)
Ad valorem	53	53	—
Other	2	—	2
	$ 283	$ 366	$ (83)
Production taxes as a percentage of revenue (Permian and Anadarko Basins)	5.6 %	5.5 %	

Taxes other than income decreased $83 million. Production taxes represented the majority of our taxes other than income, which decreased primarily due to lower oil, natural gas and NGL revenues. Drilling impact fees decreased primarily due to the timing of wells drilled in the Marcellus Shale and lower natural gas prices, which drive the fees assessed on our drilling activities.

Depreciation, Depletion and Amortization

DD&A expense consisted of the following for the periods indicated:

	Year Ended December 31,			Per Boe	
(In millions, except per Boe)	2023	2022	Variance	2023	2022
DD&A Expense					
Depletion	$ 1,509	$ 1,474	$ 35	$ 6.20	$ 6.37
Depreciation	74	91	(17)	0.30	0.40
Amortization of unproved properties	48	61	(13)	0.20	0.26
Accretion of ARO	10	9	1	0.04	0.04
	$ 1,641	$ 1,635	$ 6	$ 6.74	$ 7.07

Depletion of our producing properties is computed on a field basis using the unit-of-production method under the successful efforts method of accounting. The economic life of each producing property depends upon the estimated proved reserves for that property, which in turn depend upon the assumed realized sales price for future production. Therefore, fluctuations in oil and gas prices will impact the level of proved developed and proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our depletion expense. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, reclassifications of properties from unproved to proved and impairments of oil and gas properties will also impact depletion expense. Our depletion expense increased $35 million primarily due to increased production partially offset by a lower depletion rate of $6.20 per Boe for 2023 compared to $6.37 per Boe for 2022.

Fixed assets consist primarily of gas gathering facilities, water infrastructure, buildings, vehicles, aircraft, furniture and fixtures and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from three to 30 years. Also included in our depreciation expense is the depreciation of the right-of-use asset associated with our finance lease gathering system. Depreciation expense decreased $17 million primarily due to a non-recurring impairment charge related to certain right-of-use assets (building leases) recorded in late 2022.

Unproved oil and gas properties are amortized based on our drilling experience and our expectation of converting our unproved leaseholds to proved properties. The rate of amortization depends on the timing and success of our exploration and development program. If development of unproved properties is deemed unsuccessful and the properties are abandoned or surrendered, the capitalized costs are expensed in the period the determination is made. Amortization of unproved properties decreased $13 million primarily due to a non-recurring charge related to the release of certain leaseholds that occurred in 2022.

General and Administrative

G&A expense consists primarily of salaries and related benefits, stock-based compensation, office rent, legal and consulting fees, systems costs and other administrative costs incurred.

The table below reflects our G&A expense for the periods identified:

	Year Ended December 31,					
(In millions)	2023		2022		Variance	
G&A Expense						
General and administrative expense	$	220	$	241	$	(21)
Stock-based compensation expense		59		86		(27)
Merger-related expense		12		69		(57)
	$	291	$	396	$	(105)

G&A expense, excluding stock-based compensation and merger-related expenses, decreased $21 million primarily due to lower legal costs incurred in 2023 compared to 2022, and lower compensation and benefit costs due to the reduction in transition personnel throughout 2023.

Stock-based compensation expense will fluctuate based on the grant date fair value of awards, the number of awards, the requisite service period of the awards, estimated employee forfeitures, and the timing of the awards. Stock-based compensation expense decreased $27 million primarily due to higher stock-based compensation costs during 2022 related to the accelerated vesting of employee performance shares and vesting of certain other awards, and a gain related to our deferred compensation plan associated with the liquidation of the Coterra stock in the plan in 2023. These decreases were partially offset by higher stock-based compensation costs related to new shares granted during 2023.

Merger-related expenses decreased $57 million primarily due to lower employee-related severance and termination benefits associated with the termination of transition employees. We accrued for these costs over the transition period during 2022 and early 2023, with substantially all of our expected severance costs being fully accrued over that time period. Merger-related expenses also decreased due to $7 million of transaction-related costs associated with the merger that were incurred in 2022.

Gain (Loss) on Sale of Assets

The increase in gain (loss) on sale of assets is due to the sale of certain non-core oil and gas properties and other equipment.

Interest Expense

The table below reflects our interest expense, net for the periods indicated:

	Year Ended December 31,		
(In millions)	**2023**	**2022**	**Variance**
Interest Expense			
Interest expense	$ 82	$ 110	$ (28)
Debt premium amortization	(21)	(37)	16
Debt issuance cost amortization	3	4	(1)
Other	9	3	6
	$ 73	$ 80	$ (7)

Interest expense decreased $28 million primarily due to the repayment of our 6.51% and 5.58% weighted-average private placement senior notes in August 2022 and the redemption of $750 million of the 4.375% senior notes in late 2022.

Debt premium amortization decreased $16 million primarily due to the redemption of $750 million of the 4.375% senior notes in late 2022.

Interest Income

Interest income increased $37 million primarily due to higher interest rates on higher cash balances.

Gain on Debt Extinguishment

In 2022, we paid down $874 million of our debt for $880 million and recognized a net gain on debt extinguishment of $28 million primarily due to the write off of related debt premiums and debt issuance costs.

Income Tax Expense

(In millions)	Year Ended December 31, 2023	2022	Variance
Income Tax Expense			
Current tax expense	$ 429	$ 869	$ (440)
Deferred tax expense	74	235	(161)
	$ 503	$ 1,104	$ (601)
Combined federal and state effective income tax rate	24 %	21 %	

Income tax expense decreased $601 million primarily due to lower pre-tax income in 2023 compared to 2022, partially offset by a higher effective tax rate. The effective tax rate was higher for 2023 compared to 2022 due to differences in the non-recurring discrete items recorded during 2023 versus 2022.

2022 and 2021 Compared

For information on the comparison of the results of operations for the year ended December 31, 2022 compared to the year ended December 31, 2021, refer to Management's Discussion and Analysis of Financial Condition and Results of Operations included in the Coterra Energy Inc. Annual Report on Form 10-K for the year ended December 31, 2022, which information is incorporated by reference herein.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management 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 balance sheet, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates, and changes in our estimates are recorded when known. We consider the following to be our most critical estimates that involve judgement of management.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our oil and gas producing activities. Acquisition costs for proved and unproved properties are capitalized when incurred. Judgment is required to determine the proper classification of wells designated as developmental or exploratory, which ultimately will determine the proper accounting treatment of costs incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry-hole costs are expensed. Development costs, including costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves, are capitalized.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently imprecise, and the reserves data included in this document are only an estimate. The process relies on interpretations and judgment of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as commodity prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant variance in the interpretations or assumptions could materially affect the estimated quantity and value of our reserves and can change substantially over time. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of reservoir performance, drilling activity, commodity prices, fluctuations in operating expenses, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserves estimates are generally different from the quantities ultimately recovered.

The reserves estimates of our oil and gas properties have been prepared by our reservoir engineering staff and certain of our reserves are subject to an evaluation performed by an independent third-party petroleum consulting firm. In 2023, greater than 90 percent of the total future net revenue discounted at 10 percent attributable to our proved reserves were subject to this evaluation. For more information regarding reserves estimation, including historical reserves revisions, refer to the Supplemental Oil and Gas Information included in Item 8.

Our rate of recording DD&A expense is dependent upon our estimate of proved reserves, which are utilized in our unit-of-production calculation. If the estimates of proved and proved developed reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it uneconomic to drill and produce higher cost fields. A five percent positive or negative revision to proved reserves would result in a decrease of $0.31 per Boe and an increase of $0.35 per Boe, respectively, on our DD&A rate. This estimated impact is based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserves estimates may impact the outcome of our impairment test under applicable accounting standards. Due to the inherent imprecision of the reserves estimation process, risks associated with the operations of proved producing properties and market sensitive commodity prices utilized in our impairment analysis, we cannot determine if an impairment is reasonably likely to occur in the future.

Oil and Gas Properties

We evaluate our proved oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate an asset’s carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future commodity prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, then the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process, historical and current prices adjusted for geographical location and quality differentials, as well as other factors that we believe will impact realizable prices. Given the significant volatility in oil, natural gas and NGLs prices, estimates of such future prices are inherently imprecise. In the event that commodity prices significantly decline, we would test the recoverability of the carrying value of our oil and gas properties and, if necessary, record an impairment charge. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying oil and natural gas.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to our unproved acreage amortization based on past drilling and exploration experience, our expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the geographical areas has not significantly changed and generally ranges from three to five years. The commodity price environment may impact the capital available for our drilling activities. We have considered these impacts when determining the amortization of our unproved acreage. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $12 million or decrease by $8 million, respectively, per year.

As these properties are developed and reserves are proved, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful and the properties are abandoned or surrendered, the capitalized costs related to the unsuccessful activity are expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration and development program.

Derivative Instruments

Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The change in fair value of derivatives not designated as hedges is recorded as a component of operating revenues in gain (loss) on derivative instruments in the Consolidated Statement of Operations.

Our derivative contracts are measured based on quotes from our counterparties or internal models. Such quotes and models have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward commodity prices, basis differentials, volatility factors and interest rates for a similar length of time as the derivative contract term, as applicable. These estimates are derived from or verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of fair value also incorporates a credit adjustment for non-performance risk. We measure the non-performance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions with which we have derivative transactions, while our non-performance risk is evaluated by using credit default swap spreads for various similarly rated companies in our sector.

Our financial condition, results of operations and liquidity can be significantly impacted by changes in the market value of our derivative instruments due to volatility of commodity prices, including changes in both index prices (such as NYMEX) and basis differentials.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments include the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expenses for tax and financial reporting purposes and estimating reserves for potential adverse outcomes regarding tax positions that we have taken. We account for the uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management’s estimates of the ultimate outcome of various tax uncertainties.

We believe all of our deferred tax assets, net of any valuation allowances, will ultimately be realized, taking into consideration our forecasted future taxable income, which includes consideration of future operating conditions specifically related to commodity prices. If our estimates and judgments change regarding our ability to realize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not it will not be realized.

Our effective tax rate is subject to variability as a result of factors other than changes in federal and state tax rates and changes in tax laws which could affect us. Our effective tax rate is affected by changes in the allocation of property, payroll and revenues among states in which we operate. A small change in our estimated future tax rate could have a material effect on current period earnings.

Contingency Reserves

A provision for contingencies is charged to expense when the loss is probable and the cost is estimable. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. In certain cases, our judgment is based on the advice and opinions of legal counsel and other advisors, the interpretation of laws and regulations, which can be interpreted differently by regulators and courts of law, our experience and the experiences of other companies dealing with similar matters, and our decision on how we intend to respond to a particular matter. Actual losses can differ from estimates for various reasons, including those noted above. We monitor known and potential legal, environmental and other contingencies and make our best estimate based on the information we have. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Stock-Based Compensation

We account for stock-based compensation under the fair value method of accounting in accordance with applicable accounting standards. Under the fair value method, compensation cost is measured at the grant date for equity-classified awards and re-measured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, we use various models, including both a Black Scholes or a Monte Carlo valuation model, as determined by the specific provisions of the award. The use of these models requires significant judgment with respect to expected life, volatility and other factors.

Recently Issued Accounting Pronouncements

Refer to Note 1 of the Notes to the Consolidated Financial Statements, “Summary of Significant Accounting Policies,” for a discussion of new accounting pronouncements that affect us.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, we are subject to a variety of risks, including market risks associated with changes in commodity prices and interest rate movements on outstanding debt. The following quantitative and qualitative information is provided for financial instruments to which we were party to as of December 31, 2023 and from which we may incur future gains or losses from changes in commodity prices or interest rates.

Commodity Price Risk

Our most significant market risk exposure is pricing applicable to our oil, natural gas and NGL production. Realized prices are mainly driven by the worldwide price for oil and spot market prices for North American natural gas and NGL production. These prices have been volatile and unpredictable. To mitigate the volatility in commodity prices, we may enter into derivative instruments to hedge a portion of our production.

Derivative Instruments and Risk Management Activities

Our risk management strategy is designed to reduce the risk of commodity price volatility for our production in the oil and natural gas markets through the use of financial commodity derivatives. A committee that consists of members of senior management oversees our risk management activities. Our financial commodity derivatives generally cover a portion of our production and, while protecting us in the event of price declines, limit the benefit to us in the event of price increases. Further, if any of our counterparties defaulted, this protection might be limited as we might not receive the full benefit of our financial commodity derivatives. Please read the discussion below as well as Note 5 of the Notes to the Consolidated Financial Statements, “Derivative Instruments,” in Item 8 for a more detailed discussion of our derivatives.

Periodically, we enter into financial commodity derivatives, including collar, swap, and basis swap agreements, to protect against exposure to commodity price declines. All of our financial derivatives are used for risk management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or oil in exchange for paying a variable price based on a market-based index.

Table of Contents

As of December 31, 2023, we had the following outstanding financial commodity derivatives:

Natural Gas	2024 First Quarter	2024 Second Quarter	2024 Third Quarter	2024 Fourth Quarter	2025 First Quarter	2025 Second Quarter	2025 Third Quarter	2025 Fourth Quarter
NYMEX collars								
Volume (MMBtu)	35,490,000	44,590,000	45,080,000	16,690,000	9,000,000	9,100,000	9,200,000	9,200,000
Weighted average floor ($/MMBtu)	$ 3.00	$ 2.70	$ 2.75	$ 2.75	$ 3.25	$ 3.25	$ 3.25	$ 3.25
Weighted average ceiling ($/MMBtu)	$ 5.38	$ 3.87	$ 3.94	$ 4.23	$ 4.79	$ 4.79	$ 4.79	$ 4.79

Oil	2024 First Quarter	2024 Second Quarter	2024 Third Quarter	2024 Fourth Quarter	Fair Value Asset (Liability) (In millions)
WTI oil collars					$ 26
Volume (MBbl)	2,730	2,730	1,840	1,840	
Weighted average floor ($/Bbl)	$ 68.00	$ 68.00	$ 65.00	$ 65.00	
Weighted average ceiling ($/Bbl)	$ 91.37	$ 91.37	$ 90.01	$ 90.01	
WTI Midland oil basis swaps					(1)
Volume (MBbl)	2,730	2,730	1,840	1,840	
Weighted average differential ($/Bbl)	$ 1.16	$ 1.16	$ 1.17	$ 1.17	
					$ 25

In January 2024, the Company entered into the following financial commodity derivatives:

	2024			
Oil	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
WTI oil collars				
Volume (MBbl)	300	455	920	920
Weighted average floor ($/Bbl)	$ 65.00	$ 65.00	$ 65.00	$ 65.00
Weighted average ceiling ($/Bbl)	$ 85.02	$ 85.02	$ 81.49	$ 81.49
WTI Midland oil basis swaps				
Volume (MBbl)	300	455	920	920
Weighted average differential ($/Bbl)	$ 1.10	$ 1.10	$ 1.10	$ 1.10

A significant portion of our production for 2024 and beyond is currently unhedged and directly exposed to the volatility in commodity prices, whether favorable or unfavorable.

During 2023, natural gas collars with floor prices ranging from $3.00 to $7.50 per MMBtu and ceiling prices ranging from $4.55 to $13.08 per MMBtu covered 174.9 Bcf, or 17 percent of natural gas production at a weighted-average price of $4.23 per MMBtu.

During 2023, oil collars with floor prices ranging from $65.00 to $80.00 per Bbl and ceiling prices ranging from $89.00 to $118.30 per Bbl covered 7.1 MMBbls, or 20 percent, of oil production at a weighted-average price of $68.75 per Bbl. Oil basis swaps covered 7.6 MMBbls, or 22 percent, of oil production at a weighted-average price of $0.92 per Bbl.

We are exposed to market risk on financial commodity derivative instruments to the extent of changes in market prices of the related commodity. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of oil and natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. Our counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses related to non-performance risk of our counterparties and we do not anticipate any material impact on our financial results due to non-performance by third parties. However, we cannot be certain that we will not experience such losses in the future.

Interest Rate Risk

At December 31, 2023, we had total debt of $2.2 billion (with a principal amount of $2.1 billion). All of our outstanding debt is based on fixed interest rates and, as a result, we do not have significant exposure to movements in market interest rates with respect to such debt. Our revolving credit agreement provides for variable interest rate borrowings; however, we did not have any borrowings outstanding as of December 31, 2023 and, therefore, no related exposure to interest rate risk.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash, cash equivalents and restricted cash approximate fair value due to the short-term maturities of these instruments.

The fair value of our senior notes is based on quoted market prices. The fair value of our private placement senior notes is based on third-party quotes which are derived from credit spreads for the difference between the issue rate and the period end market rate and other unobservable inputs.

The carrying amount and estimated fair value of debt is as follows:

	December 31, 2023		December 31, 2022	
(In millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 2,161	$ 2,015	$ 2,181	$ 1,955
Current maturities	(575)	(565)	—	—
Long-term debt, excluding current maturities	$ 1,586	$ 1,450	$ 2,181	$ 1,955

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Coterra Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Coterra Energy Inc. and its subsidiaries (the "Company") as of December 31, 2023 and 2022, and the related consolidated statements of operations, of comprehensive income, of stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2023, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters 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.

The Impact of Proved Developed Oil and Natural Gas Reserves on Proved Oil and Gas Properties, Net

As described in Notes 1 and 3 to the consolidated financial statements, a significant portion of the Company’s properties and equipment, net balance of $12,835 million as of December 31, 2023 and depreciation, depletion and amortization (DD&A) expense of $1,635 million for the year ended December 31, 2023 relate to proved oil and gas properties. The Company uses the successful efforts method of accounting for its oil and gas producing activities. As disclosed by management, the Company’s rate of recording DD&A expense is dependent upon the estimate of proved reserves and proved developed reserves, which are utilized in the unit-of-production calculation. In estimating proved oil and natural gas reserves, management relies on interpretations and judgment of available geological, geophysical, engineering and production data, as well as the use of certain economic assumptions such as commodity prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved developed oil and natural gas reserves on proved oil and gas properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved developed oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved developed oil and natural gas reserves.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s estimates of proved developed oil and natural gas reserves. The work of management’s specialists was used in performing the procedures to evaluate the reasonableness of the proved developed oil and natural gas reserves. As a basis for using this work, the specialists’ qualifications were understood and the Company’s relationship with the specialists was assessed. The procedures performed also included evaluating the methods and assumptions used by the specialists, testing the completeness and accuracy of data used by the specialists, and evaluating the specialists’ findings.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 23, 2024

We have served as the Company’s auditor since 1989.

COTERRA ENERGY INC.
CONSOLIDATED BALANCE SHEET

(In millions, except per share amounts)	December 31, 2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 956	$ 673
Restricted cash	9	10
Accounts receivable, net	843	1,221
Income taxes receivable	51	89
Inventories	59	63
Derivative instruments	85	146
Other current assets	12	9
Total current assets	2,015	2,211
Properties and equipment, net (Successful efforts method)	17,933	17,479
Other assets	467	464
	$ 20,415	$ 20,154
LIABILITIES, REDEEMABLE PREFERRED STOCK AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 803	$ 844
Current portion of long-term debt	575	—
Accrued liabilities	261	328
Interest payable	21	21
Total current liabilities	1,660	1,193
Long-term debt	1,586	2,181
Deferred income taxes	3,413	3,339
Asset retirement obligations	280	271
Other liabilities	429	500
Total liabilities	7,368	7,484
Commitments and contingencies (Note 8)		
Cimarex redeemable preferred stock	8	11
Stockholders' equity		
Common stock:		
Authorized — 1,800 shares of $0.10 par value in 2023 and 2022		
Issued — 751 shares and 768 shares in 2023 and 2022, respectively	75	77
Additional paid-in capital	7,587	7,933
Retained earnings	5,366	4,636
Accumulated other comprehensive income	11	13
Total stockholders' equity	13,039	12,659
	$ 20,415	$ 20,154

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

COTERRA ENERGY INC.
CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In millions, except per share amounts)	**2023**	**2022**	**2021**
OPERATING REVENUES			
Natural gas	$ 2,292	$ 5,469	$ 2,798
Oil	2,667	3,016	616
NGL	644	964	243
Gain (loss) on derivative instruments	230	(463)	(221)
Other	81	65	13
	5,914	9,051	3,449
OPERATING EXPENSES			
Direct operations	562	460	156
Gathering, processing and transportation	975	955	663
Taxes other than income	283	366	83
Exploration	20	29	18
Depreciation, depletion and amortization	1,641	1,635	693
General and administrative	291	396	270
	3,772	3,841	1,883
Gain (loss) on sale of assets	12	(1)	(2)
INCOME FROM OPERATIONS	2,154	5,209	1,564
Interest expense	73	80	62
Interest income	(47)	(10)	—
Gain on debt extinguishment	—	(28)	—
Other income	—	(2)	—
Income before income taxes	2,128	5,169	1,502
Income tax expense	503	1,104	344
NET INCOME	$ 1,625	$ 4,065	$ 1,158
Earnings per share			
Basic	$ 2.14	$ 5.09	$ 2.30
Diluted	$ 2.13	$ 5.08	$ 2.29
Weighted-average common shares outstanding			
Basic	756	796	503
Diluted	760	799	504

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

COTERRA ENERGY INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended December 31,			
(In millions)	2023	2022	2021	
Net income	$1,625	$4,065	$1,158	
Postretirement benefits:				
Amortization of net actuarial gain[1]	$ (2)	$ —	$ —	0
Net actuarial gain[2]	—	12	—	
Amortization of prior service credit[3]	—	(1)	(1)	
Plan amendment [4]	—	1	—	
Total other comprehensive (loss) income	(2)	12	(1)	
Comprehensive income	$1,623	$4,077	$1,157	

(1) Net of income taxes of less than $1 million for the year ended December 31, 2023.
(2) Net of income taxes of $3 million for the year ended December 31, 2022 .
(3) Net of income taxes of less than $1 million for each of the years ended December 31, 2022 and 2021.
(4) Net of income taxes of less than $1 million for the year ended December 31, 2022.

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

COTERRA ENERGY INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

(In millions)	2023	2022	2021
	Year Ended December 31,		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,625	$ 4,065	$ 1,158
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,641	1,635	693
Deferred income tax expense	74	235	126
(Gain) loss on sale of assets	(12)	1	2
(Gain) loss on derivative instruments	(230)	463	221
Net cash received (paid) in settlement of derivative instruments	284	(762)	(431)
Amortization of debt premium and debt issuance costs	(18)	(40)	(10)
Gain on debt extinguishment	—	(28)	—
Stock-based compensation and other	57	73	52
Changes in assets and liabilities:			
Accounts receivable, net	378	(184)	(229)
Income taxes	38	(118)	34
Inventories	4	(24)	5
Other current assets	(3)	(4)	(4)
Accounts payable and accrued liabilities	(180)	96	47
Interest payable	—	(5)	6
Other assets and liabilities	—	53	(3)
Net cash provided by operating activities	3,658	5,456	1,667
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for drilling, completion and other fixed asset additions	(2,089)	(1,700)	(723)
Capital expenditures for leasehold and property acquisitions	(10)	(10)	(5)
Proceeds from sale of assets	40	36	8
Cash received from Merger	—	—	1,033
Net cash (used in) provided by investing activities	(2,059)	(1,674)	313
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from debt	—	—	100
Repayments of debt	—	(874)	(288)
Repayments of finance leases	(6)	(6)	(2)
Common stock repurchases	(405)	(1,250)	—
Dividends paid	(890)	(1,992)	(780)
Cash paid for conversion of redeemable preferred stock	(1)	(10)	—
Tax withholding on vesting of stock awards	(10)	(25)	(114)
Capitalized debt issuance costs	(7)	—	(4)
Cash received for stock option exercises	2	12	2
Net cash used in financing activities	(1,317)	(4,145)	(1,086)
Net increase (decrease) in cash, cash equivalents			

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

COTERRA ENERGY INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In millions, except per share amounts)	Common Shares	Common Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total
Balance at December 31, 2020	478	$ 48	79	$ (1,823)	$ 1,804	$ 2	$ 2,185	$ 2,216
Net income	—	—	—	—	—	—	1,158	1,158
Issuance of common stock for merger	408	41	—	—	9,042	—	—	9,083
Issuance of replacement awards and options for merger consideration	4	—	—	—	37	—	—	37
Exercise of stock options	—	—	—	—	2	—	—	2
Stock amortization and vesting	3	—	—	(3)	26	—	—	23
Cash dividends:								
Common stock at $1.12 per share	—	—	—	—	—	—	(779)	(779)
Preferred stock at $20.3125 per share	—	—	—	—	—	—	(1)	(1)
Other comprehensive loss	—	—	—	—	—	(1)	—	(1)
Balance at December 31, 2021	893	$ 89	79	$ (1,826)	$10,911	$ 1	$ 2,563	$11,738
Net income	—	—	—	—	—	—	4,065	4,065
Exercise of stock options	1	—	—	—	12	—	—	12
Stock amortization and vesting	1	1	1	(9)	54	—	—	46
Common stock repurchases	—	—	48	(1,250)	—	—	—	(1,250)
Common stock retirements	(128)	(13)	(128)	3,085	(3,072)	—	—	—
Conversion of Cimarex redeemable preferred stock	1	—	—	—	28	—	—	28
Cash dividends:								
Common stock at $2.49 per share	—	—	—	—	—	—	(1,991)	(1,991)

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Coterra Energy Inc. and its subsidiaries ("Coterra" or the "Company") are engaged in the development, exploration and production of oil, natural gas and NGLs exclusively within the continental U.S. The Company's exploration and development activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

The Company operates in one segment, oil and natural gas development, exploration and production. The Company's oil and gas properties are managed as a whole rather than through discrete operating segments. Operational information is tracked by geographic area; however, financial performance is assessed as a single enterprise and not on a geographic basis. Allocation of resources is made on a project basis across the Company's entire portfolio without regard to geographic areas.

The consolidated financial statements include the accounts of the Company and its subsidiaries after eliminating all significant intercompany balances and transactions. Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on previously reported stockholders' equity, net income or cash flows.

The Company and Cimarex Energy Co. ("Cimarex") completed a merger transaction on October 1, 2021 (the "Merger"), pursuant to an agreement entered into by the Company and Cimarex (the "Merger Agreement"). Refer to Note 2, "Acquisitions," for further information. Additionally, on October 1, 2021, Cabot Oil & Gas Corporation changed its name to Coterra Energy Inc.

Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less and deposits in money market funds and other investments that are readily convertible to cash to be cash equivalents. Cash and cash equivalents were primarily concentrated in four financial institutions at December 31, 2023. The Company periodically assesses the financial condition of its financial institutions and considers any possible credit risk to be minimal.

Restricted Cash

Restricted cash includes cash that is legally or contractually restricted as to withdrawal or usage. As of December 31, 2023 and 2022, the restricted cash balance of $9 million and $10 million, respectively, includes cash deposited in escrow accounts that are restricted for use.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts based on the Company's estimate of future expected credit losses on outstanding receivables.

Inventories

Inventories are primarily comprised of tubular goods and well equipment and are carried at average cost. Inventories are assessed periodically for obsolescence.

Properties and Equipment

Oil and Gas Properties

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed. Development costs, including the costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. The determination is based on a process which relies on interpretations of available geologic, geophysical and engineering data. If a well is determined to be successful, the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful, the capitalized drilling costs will be charged to exploration expense in the Consolidated Statement of Operations in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether reserves have been found only as long as: (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and (2) drilling of an additional exploratory well is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired and its costs are charged to exploration expense.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs and acquisition costs, are depreciated and depleted on a field basis by the unit-of-production method using proved developed and proved reserves, respectively.

Costs of sold or abandoned properties that make up a part of an amortization base (partial field) remain in the amortization base if the unit-of-production rate is not significantly affected. If significant, a gain or loss, if any, is recognized and the sold or abandoned properties are retired. A gain or loss, if any, is also recognized when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold.

The Company evaluates its proved oil and gas properties for impairment whenever events or changes in circumstances indicate an asset’s carrying amount may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on estimates of future commodity prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying oil and natural gas.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to the Company’s unproved acreage amortization based on past drilling and exploration experience, the Company’s expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights.

Fixed Assets

Fixed assets consist primarily of gas gathering systems, water infrastructure, buildings, vehicles, aircraft, furniture and fixtures, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from three to 30 years.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Asset retirement costs for oil and gas properties are depreciated using the unit-of-production method, while asset retirement costs for other assets are depreciated using the straight-line method over estimated useful lives.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense is included in DD&A expense in the Consolidated Statement of Operations.

Derivative Instruments

The Company enters into financial derivative contracts, primarily collars, swaps and basis swaps, to manage its exposure to price fluctuations on a portion of its anticipated future production volumes. All of the Company’s derivatives are used for risk management purposes and are not held for trading purposes. The Company has elected not to designate its financial derivative instruments as accounting hedges under the accounting guidance.

The Company evaluates all of its physical purchase and sale contracts to determine if they meet the definition of a derivative. For contracts that meet the definition of a derivative, the Company may elect the normal purchase normal sale (“NPNS”) exception provided under the applicable accounting guidance and account for the contract using the accrual method of accounting. Contracts that do not qualify for or for which the Company elects not to apply the NPNS exception are accounted for at fair value.

All derivatives, except for derivatives that qualify for the NPNS exception, are recognized on the balance sheet and are measured at fair value. At the end of each quarterly period, these derivatives are marked to market. As a result, changes in the fair value of derivatives are recognized in operating revenues in gain (loss) on derivative instruments. The resulting cash flows are reported as cash flows from operating activities.

Leases

The Company determines if an arrangement is, or contains, a lease at inception based on whether that contract conveys the right to control the use of an identified asset in exchange for consideration for a period of time. Operating leases are included in right-of-use assets ("ROU assets") and lease liabilities (current and non-current) in the Consolidated Balance Sheet. Financing leases are included in properties and equipment, net and lease liabilities (current and non-current) in the Consolidated Balance Sheet. Short-term leases (a lease that, at commencement, has a lease term of one year or less and does not contain a purchase option that the Company is reasonably certain to exercise) are not recognized in ROU assets and lease liabilities. For all operating leases, lease and non-lease components are accounted for as a single lease component.

ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the leases. ROU assets and lease liabilities are recognized at the lease commencement date based on the present value of minimum lease payments over the lease term. Most leases do not provide an implicit interest rate; therefore, the Company uses its incremental borrowing rate based on the information available at the inception date to determine the present value of the lease payments. Lease terms include options to extend the lease when it is reasonably certain that the Company will exercise that option. Lease cost for lease payments is recognized on a straight-line basis over the lease term. Certain leases have payment terms that vary based on the usage of the underlying assets. Variable lease payments are not included in ROU assets and lease liabilities.

Fair Value of Assets and Liabilities

The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in its financial statements. 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 (exit price). The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company is able to classify fair value balances based on the observability of these inputs. The authoritative guidance for fair value measurements establishes three levels of the fair value hierarchy, defined as follows:

- Level 1: Unadjusted, quoted prices for identical assets or liabilities in active markets.

- Level 2: Quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability.

- Level 3: Significant, unobservable inputs for use when little or no market data exists, requiring a significant degree of judgment.

The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under the accounting guidance, the lowest level that contains significant inputs used in the valuation should be chosen.

Revenue Recognition

The Company's revenue is typically generated from contracts to sell oil, natural gas and NGLs produced from interests in oil and gas properties owned by the Company. These contracts generally require the Company to deliver a specific amount of a commodity per day for a specified number of days at a price that is either fixed or variable. The contracts specify a delivery point which represents the point at which control of the product is transferred to the customer. The Company has determined that these contracts represent multiple performance obligations which are satisfied when control of the commodity transfers to the customer, typically through the delivery of the specified commodity to a designated delivery point.

Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. The Company recognizes revenue in the amount that reflects the consideration it expects to be entitled to in exchange for transferring control of those goods to the customer. The contract consideration in the Company’s variable price contracts are typically allocated to specific performance obligations in the contract according to the price stated in the contract. Amounts allocated in the Company’s fixed price contracts are based on the standalone selling price of those products in the context of long-term, fixed price contracts, which generally approximates the contract price. Payment is generally received one or two months after the sale has occurred.

The Company has not adjusted the promised amount of consideration for the effects of a significant financing component if the Company expects, at contract inception, that the period between when the Company transfers a promised good or service to the customer and when the customer pays for that good or service will be one year or less.

For contracts with an original expected term of one year or less, the Company has elected not to disclose the transaction price allocated to the unsatisfied performance obligations. For contracts with terms greater than one year, the Company has elected not to disclose the price allocated to the unsatisfied performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Since each unit of the respective commodity typically represents a separate performance obligation, future volumes are considered wholly unsatisfied, and disclosure of the transaction price allocated to the remaining performance obligation is not required.

Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction, and that are collected by the Company from a customer, are excluded from revenue.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company follows the “equity first” approach when applying the limitation for certain executive compensation in excess of $1 million to future compensation. The limitation is first applied to stock-based compensation that vests in future tax years before considering cash compensation paid in a future period. Accordingly, the Company records a deferred tax asset for stock-based compensation expense recorded in the current period, and reverses the temporary difference in the future period, during which the stock-based compensation becomes deductible for tax purposes.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management’s estimates of the ultimate outcome of various tax uncertainties.

The Company recognizes accrued interest related to uncertain tax positions in interest expense and accrued penalties related to such positions in G&A expense in the Consolidated Statement of Operations.

Stock-Based Compensation

The Company accounts for stock-based compensation under the fair value method of accounting. Under this method, compensation cost is measured at the grant date for equity-classified awards and re-measured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, the Company uses a Black Scholes or Monte Carlo valuation model based on the specific provisions of the award. Stock-based compensation cost for all types of awards is included in G&A expense in the Consolidated Statement of Operations.

The Company records excess tax benefits and tax deficiencies on stock-based compensation in the income statement upon vesting of the respective awards. Excess tax benefits and tax deficiencies are included in cash flows from operating activities in the Consolidated Statement of Cash Flow.

Cash paid by the Company when directly withholding shares from employee stock-based compensation awards for tax-withholding purposes are classified as financing activities in the Consolidated Statement of Cash Flow.

Earnings per Share

The Company calculates earnings per share recognizing that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are “participating securities” and, therefore, should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Certain of the Company’s unvested share-based payment awards, consisting of restricted stock, qualify as participating securities. The Company’s participating securities do not have a contractual obligation to share in the losses of the entity and, therefore, net losses are not allocated to them.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Credit and Concentration Risk

Substantially all of the Company’s accounts receivable result from the sale of oil, natural gas and NGLs to third parties in the oil and gas industry and joint interest billings with other participants in joint operations. This concentration of purchasers and joint owners may impact the Company’s overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties.

During the year ended December 31, 2023, two customers accounted for approximately 19 percent and 17 percent of the Company’s total sales. During the year ended December 31, 2022, two customers accounted for approximately 13 percent and 11 percent of the Company’s total sales. During the year ended December 31, 2021, no customer accounted for more than 10 percent of the Company’s total sales.

The Company does not believe that the loss of any of its major customers would have a material adverse effect on it because alternative customers are readily available. If any one of the Company’s major customers were to stop purchasing the Company’s production, the Company believes there are a number of other purchasers to whom it could sell its production. If multiple significant customers were to stop purchasing the Company’s production, the Company believes there could be some initial challenges, but the Company believes it has ample alternative markets to handle any sales disruptions.

The Company regularly monitors the creditworthiness of its customers and may require parent company guarantees, letters of credit or prepayments when necessary. Historically, losses associated with uncollectible receivables have been insignificant.

Use of Estimates

In preparing financial statements, the Company follows GAAP. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and gas reserves and related cash flow estimates which are used to compute depreciation, depletion and amortization and impairments of proved oil and gas properties. Other estimates include oil, natural gas and NGL revenues and expenses, fair value of derivative instruments, estimates of expenses related to legal, environmental and other contingencies, asset retirement obligations, postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.

Recently Issued Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. This standard includes additional clarification and implementation guidance related to significant expense principle, single reportable segment entities, and disclosing multiple measures of a segment’s profit or loss. The ASU will be effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted and retrospective application. The adoption of ASU No. 2023-07 is not expected to have any effect on the Company's financial position, results of operations or cash flows as it modifies disclosure requirements only.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes (Topic 740) Improvements to Income Tax Disclosure. This ASU requires additions to income tax disclosures, including among other things, a further breakout of amounts paid for taxes between federal, state, and foreign taxing jurisdictions, and the disaggregation of the rate reconciliation into eight specific categories with both dollar amounts and percentages. The ASU will be effective for fiscal years beginning after December 15, 2024, and interim periods within fiscal years beginning after December 15, 2025, with early adoption permitted. The adoption of ASU No. 2023-09 is not expected to have any effect on the Company’s financial position, results of operations or cash flows as it modifies disclosure requirements only.

2. Acquisitions

Cimarex Energy Co.

On October 1, 2021, the Company and Cimarex completed the Merger. Cimarex is an oil and gas exploration and production company with operations in Texas, New Mexico and Oklahoma. Upon the effectiveness of the Merger, each eligible share of Cimarex common stock was converted into the right to receive 4.0146 shares of common stock of the Company. Based on the closing price of Coterra’s common stock on October 1, 2021, the total value of such shares of Coterra common stock was approximately $9.1 billion. The Company and Cimarex intended for the Merger to qualify as a tax-free reorganization for U.S. federal income tax purposes.

Post-Acquisition Operating Results

Cimarex contributed the following to the Company’s 2021 consolidated operating results.

(in millions)	October 1, 2021 through December 31, 2021
Revenue	$ 1,129
Net income	394

Unaudited Pro Forma Financial Information

The results of Cimarex’s operations have been included in the Company’s consolidated financial statements since October 1, 2021, the effective date of the Merger. The following supplemental pro forma information for the year ended December 31, 2021, has been prepared to give effect to the Cimarex acquisition as if it had occurred on January 1, 2020. The information below reflects pro forma adjustments based on available information and certain assumptions that Coterra believes are factual and supportable. The pro forma results of operations do not include any cost savings or other synergies resulting from the acquisition or any estimated costs that have been or will be incurred by Coterra to integrate the acquired assets.

The pro forma information is not necessarily indicative of the results that might have occurred had the transaction actually taken place on January 1, 2020, and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities and other factors.

(In millions, except per share information)	Year Ended December 31, 2021
Pro forma revenue	$ 5,236
Pro forma net income	1,205
Pro forma basic earnings per share	$ 1.49
Pro forma diluted earnings per share	$ 1.48

Other Information

In connection with the Merger, the Company recognized $42 million of transaction costs for the year ended December 31, 2021. These fees primarily related to bank, legal and accounting fees and are included in G&A expense in the Consolidated Statement of Operations.

3. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

(In millions)	December 31, 2023	December 31, 2022
Proved oil and gas properties	$ 19,582	$ 17,085
Unproved oil and gas properties	4,617	5,150
Gathering and pipeline systems	527	450
Land, buildings and other equipment	216	183
Finance lease right-of-use asset	25	24
	24,967	22,892
Accumulated DD&A	(7,034)	(5,413)
	$ 17,933	$ 17,479

Capitalized Exploratory Well Costs

As of and for the years ended December 31, 2023, 2022 and 2021, the Company did not have any projects with exploratory well costs capitalized for a period of greater than one year after drilling.

4. Long-Term Debt and Credit Agreements

The following table includes a summary of the Company’s long-term debt.

(In millions)	December 31, 2023	December 31, 2022
Total debt		
3.65% weighted-average private placement senior notes[(1)]	$ 825	$ 825
3.90% senior notes due May 15, 2027	750	750
4.375% senior notes due March 15, 2029	500	500
Revolving credit agreement	—	—
Total	2,075	2,075
Unamortized debt premium	90	111
Unamortized debt issuance costs	(4)	(5)
Total debt	$ 2,161	$ 2,181
Less: current portion of long-term debt	575	—
Long-term debt	$ 1,586	$ 2,181

(1) The 3.65% weighted-average senior notes have bullet maturities of $575 million and $250 million due in September 2024 and 2026, respectively.

Private Placement Senior Notes

The private placement senior notes are general, unsecured obligations of the Company. Interest on each series of private placement senior notes is payable semi-annually. Under the terms of the note purchase agreement, the Company may prepay all or any portion of the notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium.

During 2022, the Company repaid $37 million of its 6.51% weighted-average senior notes for $38 million and $87 million of its 5.58% weighted-average senior notes for $92 million prior to their original maturity dates, and recognized a net loss on debt extinguishment of $7 million.

The note purchase agreement provides that the Company must maintain a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of not less than 2.8 to 1.0 and requires the Company to maintain, as of the last day of any fiscal quarter, a maximum ratio of total debt to consolidated EBITDAX for the trailing four quarters of not more than 3.0 to 1.0. There are also various other covenants and events of default customarily found in such debt instrument.

As of December 31, 2023, the Company was in compliance with its financial covenants under the private placement senior notes.

Senior Notes

The 3.90% senior notes due 2027 and the 4.375% senior notes due 2029 (the “Senior Notes”) are general, unsecured obligations of the Company. Interest on each series of Senior Notes is payable semi-annually. Under the terms of the indenture documents governing the Senior Notes, the Company may redeem all or any portion of the Senior Notes of each series on any date at a price equal to the principal amount thereof plus applicable redemption prices described in the governing indentures. The Company is also subject to various covenants and events of default customarily found in such debt instruments.

In 2022, the Company redeemed the $750 million principal amount of its 4.375% Senior Notes for approximately $750 million and recognized a net gain on debt extinguishment of $35 million primarily due to the write off of the associated debt premiums and debt issuance costs.

Revolving Credit Agreement

On March 10, 2023, the Company entered into a revolving credit agreement (the “Credit Agreement”) with JPMorgan Chase Bank, N.A., as administrative agent (“JPMorgan”), and certain lenders and issuing banks party thereto. The aggregate revolving commitments under the Credit Agreement are $1.5 billion, with a discretionary swingline sub-facility of up to $100 million and a letter of credit sub-facility of up to $500 million. The Company may also increase the revolving commitments under the Credit Agreement by up to an additional $500 million subject to certain conditions and the agreement of the lenders providing commitments with respect to such increase.

Borrowings under the Credit Agreement bear interest at a rate per annum equal to, at the Company’s option, either (i) a term secured overnight financing rate (“SOFR”) plus a 0.10 percent credit spread adjustment for all tenors or (ii) a base rate, in each case plus an interest rate margin which ranges from 0 to 75 basis points for base rate loans and 100 to 175 basis points for term SOFR loans based on the Company’s credit rating. The commitment fee on the unused available credit is calculated at annual rates ranging from 10 basis points to 27.5 basis points based on the Company’s credit rating. The Credit Agreement matures on March 10, 2028. The maturity date can be extended for additional one-year periods on up to two occasions upon the agreement of the Company and lenders holding at least 50 percent of the commitments under the Credit Agreement.

The Credit Agreement contains customary covenants, including the maintenance of a maximum leverage ratio of no more than 3.0 to 1.0 as of the last day of any fiscal quarter. At such time as the Company has no other debt in a principal amount in excess of $75 million outstanding that has a financial maintenance covenant based on a substantially similar leverage ratio, in lieu of such maximum leverage ratio covenant, the revolving credit agreement will instead require maintenance of a ratio of total debt to total capitalization of no more than 65 percent (with all calculations based on definitions contained in the Credit Agreement).

Concurrently with the Company’s entry into the Credit Agreement, the Company terminated its then-existing Second Amended and Restated Credit Agreement, dated as of

April 22, 2019, with the lenders party thereto and JPMorgan, as administrative agent thereunder.

At December 31, 2023, there were no borrowings outstanding under the Company's Credit Agreement and unused commitments were $1.5 billion.

Table of Contents

5. Derivative Instruments

As of December 31, 2023, the Company had the following outstanding financial commodity derivatives:

	2024				2025			
Natural Gas	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
NYMEX collars								
Volume (MMBtu)	35,490,000	44,590,000	45,080,000	16,690,000	9,000,000	9,100,000	9,200,000	9,200,000
Weighted average floor ($/MMBtu)	$ 3.00	$ 2.70	$ 2.75	$ 2.75	$ 3.25	$ 3.25	$ 3.25	$ 3.25
Weighted average ceiling ($/MMBtu)	$ 5.38	$ 3.87	$ 3.94	$ 4.23	$ 4.79	$ 4.79	$ 4.79	$ 4.79

	2024			
Oil	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
WTI oil collars				
Volume (MBbl)	2,730	2,730	1,840	1,840
Weighted average floor ($/Bbl)	$ 68.00	$ 68.00	$ 65.00	$ 65.00
Weighted average ceiling ($/Bbl)	$ 91.37	$ 91.37	$ 90.01	$ 90.01
WTI Midland oil basis swaps				
Volume (MBbl)	2,730	2,730	1,840	1,840
Weighted average differential ($/Bbl)	$ 1.16	$ 1.16	$ 1.17	$ 1.17

In January 2024, the Company entered into the following financial commodity derivatives:

	2024			
Oil	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
WTI oil collars				
Volume (MBbl)	300	455	920	920
Weighted average floor ($/Bbl)	$ 65.00	$ 65.00	$ 65.00	$ 65.00
Weighted average ceiling ($/Bbl)	$ 85.02	$ 85.02	$ 81.49	$ 81.49
WTI Midland oil basis swaps				
Volume (MBbl)	300	455	920	920
Weighted average differential ($/Bbl)	$ 1.10	$ 1.10	$ 1.10	$ 1.10

Effect of Derivative Instruments on the Consolidated Balance Sheet

		Fair Values of Derivative Instruments			
		Derivative Assets		Derivative Liabilities	
		December 31,		December 31,	
(In millions)	**Balance Sheet Location**	**2023**	**2022**	**2023**	**2022**
Commodity contracts	Derivative instruments (current)	$ 85	$ 146	$ —	$ —
Commodity contracts	Other assets (non-current)	7	—	—	—
		$ 92	$ 146	$ —	$ —

Offsetting of Derivative Assets and Liabilities in the Consolidated Balance Sheet

(In millions)	December 31, 2023	2022
Derivative assets		
Gross amounts of recognized assets	$ 93	$ 147
Gross amounts offset in the consolidated balance sheet	(1)	(1)
Net amounts of assets presented in the consolidated balance sheet	92	146
Gross amounts of financial instruments not offset in the consolidated balance sheet	1	2
Net amount	$ 93	$ 148
Derivative liabilities		
Gross amounts of recognized liabilities	$ 1	$ 1
Gross amounts offset in the consolidated balance sheet	(1)	(1)
Net amounts of liabilities presented in the consolidated balance sheet	—	—
Gross amounts of financial instruments not offset in the consolidated balance sheet	—	1
Net amount	$ —	$ 1

Effect of Derivative Instruments on the Consolidated Statement of Operations

(In millions)	Year Ended December 31, 2023	2022	2021
Cash received (paid) on settlement of derivative instruments			
Gas contracts	$ 280	$ (438)	$ (307)
Oil contracts	4	(324)	(124)
Non-cash gain (loss) on derivative instruments			
Gas contracts	(72)	149	99
Oil contracts	18	150	111
	$ 230	$ (463)	$ (221)

Additional Disclosures about Derivative Instruments

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligations under the agreements. The Company's counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and its derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty. The Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable.

Certain counterparties to the Company’s derivative instruments are also lenders under its Credit Agreement. The Company’s Credit Agreement and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of the Company’s liabilities thereunder if the Company defaults on other material indebtedness. The Company also has netting arrangements with each of its counterparties that allow it to offset assets and liabilities from separate derivative contracts with that counterparty.

6. Fair Value Measurements

Financial Assets and Liabilities

The following fair value hierarchy table presents information about the Company’s financial assets and liabilities measured at fair value on a recurring basis:

(In millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2023
Assets				
Deferred compensation plan	$ 33	$ —	$ —	$ 33
Derivative instruments	—	—	93	93
Total assets	$ 33	$ —	$ 93	$ 126
Liabilities				
Deferred compensation plan	$ 33	$ —	$ —	$ 33
Derivative instruments	—	—	1	1
Total liabilities	$ 33	$ —	$ 1	$ 34

(In millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
Assets				
Deferred compensation plan	$ 43	$ —	$ —	$ 43
Derivative instruments	—	—	147	147
Total assets	$ 43	$ —	$ 147	$ 190
Liabilities				
Deferred compensation plan	$ 55	$ —	$ —	$ 55
Derivative instruments	—	—	1	1
Total liabilities	$ 55	$ —	$ 1	$ 56

The Company’s investments associated with its deferred compensation plan consist of mutual funds and deferred shares of the Company’s common stock that are publicly traded and for which market prices are readily available. In early 2023, all shares of the Company’s common stock held in the deferred compensation plan were sold and invested in other investment options.

The derivative instruments were measured based on quotes from the Company's counterparties or internal models. Such quotes and models have been derived using an income approach that considers various inputs, including current market and contractual prices for the underlying instruments, quoted forward commodity prices, basis differentials, volatility factors and interest rates for a similar length of time as the derivative contract term as applicable. Estimates are derived from or verified using relevant NYMEX futures contracts and are compared to multiple quotes obtained from counterparties. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk. The Company measured the non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions with which it has derivative contracts while non-performance risk of the Company is evaluated using credit default swap spreads for various similarly rated companies in the same sector as the Company. The Company has not incurred any losses related to non-performance risk of its counterparties and does not anticipate any material impact on its financial results due to non-performance by third parties.

The most significant unobservable inputs relative to the Company's Level 3 derivative contracts are basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

(In millions)	Year Ended December 31, 2023	2022	2021
Balance at beginning of period	$ 146	$ (152)	$ 24
Total gain (loss) included in earnings	230	(446)	(532)
Settlement (gain) loss	(284)	744	356
Balance at end of period	$ 92	$ 146	$ (152)
Change in unrealized gains (losses) relating to assets and liabilities still held at the end of the period	$ 92	$ 179	$ (154)

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of oil and gas properties or acquisitions, at fair value on a nonrecurring basis. As none of the Company's other non-financial assets and liabilities were measured at fair value as of December 31, 2023, 2022 and 2021, additional disclosures were not required.

The estimated fair value of the Company's asset retirement obligations at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instruments could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents and restricted cash approximate fair value, due to the short-term maturities of these instruments. Cash and cash equivalents and restricted cash are classified as Level 1 in the fair value hierarchy and the remaining financial instruments are classified as Level 2.

The fair value of the Company's Senior Notes is based on quoted market prices, which is classified as Level 1 in the fair value hierarchy. The fair value of the Company's private placement senior notes is based on third-party quotes which are derived from credit spreads for the difference between the issue rate and the period end market rate and other unobservable inputs. The Company's private placement senior notes are valued using a market approach and are classified as Level 3 in the fair value hierarchy.

The carrying amount and estimated fair value of debt is as follows:

	December 31, 2023		December 31, 2022	
(In millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 2,161	$ 2,015	$ 2,181	$ 1,955
Current maturities	(575)	(565)	—	—
Long-term debt, excluding current maturities	$ 1,586	$ 1,450	$ 2,181	$ 1,955

7. Asset Retirement Obligations

Activity related to the Company's asset retirement obligations is as follows:

	Year Ended December 31,		
(In millions)	2023	2022	2021
Balance at beginning of period	$ 277	$ 263	$ 86
Liabilities assumed in Merger	—	—	175
Liabilities incurred	6	10	6
Liabilities settled	(1)	(3)	(10)
Liabilities divested	(4)	(2)	—
Accretion expense	11	9	6
Balance at end of period	289	277	$ 263
Less: current asset retirement obligation	(9)	(6)	(4)
Noncurrent asset retirement obligation	$ 280	$ 271	$ 259

8. Commitments and Contingencies

Gathering, Processing and Transportation Agreements

Gathering, Processing and Transportation Commitments

The Company has entered into certain gathering and transportation agreements with various pipeline carriers. Under certain of these agreements, the Company is obligated to ship minimum daily quantities, or pay for any deficiencies at a specified rate. The Company's forecasted production to be shipped on these pipelines is expected to exceed minimum daily quantities provided in the agreements. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

As of December 31, 2023, the Company's future minimum obligations under gathering and transportation agreements are as follows:

(In millions)	
2024	$ 123
2025	192
2026	174
2027	168
2028	131
Thereafter	821
	$ 1,609

Other Gathering and Processing Volume Commitments

The Company has entered into certain gas processing agreements. Under certain of these agreements, the Company is obligated to process minimum daily quantities, or pay for any deficiencies at a specified rate. The Company’s forecasted production to be processed under most of these agreements is expected to exceed minimum daily quantities provided in the agreements.

Table of Contents

As of December 31, 2023, the Company's future minimum obligations under gas processing agreements are as follows:

(In millions)		
2024	$	97
2025		96
2026		84
2027		80
2028		72
Thereafter		85
	$	514

The Company also has minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. Under certain of these agreements, the Company is obligated to deliver minimum daily quantities, or pay for any deficiencies at a specified rate. The Company's forecasted production to be delivered under most of these agreements is expected to exceed minimum daily quantities provided in the agreements.

As of December 31, 2023, the Company's future minimum obligations under these delivery commitments are as follows:

(In millions)		
2024	$	37
2025		27
2026		24
2027		18
2028		13
Thereafter		—
	$	119

As of December 31, 2023, the Company had accrued a liability of $11 million associated with these commitments, representing the present value of estimated amounts payable due to insufficient forecasted delivery volumes.

Water Delivery Commitments

The Company has minimum volume water delivery commitments associated with a water services agreement that expires in 2030. The Company is obligated to deliver minimum daily quantities or pay for any deficiencies at a specified rate.

As of December 31, 2023, the Company's future minimum obligations under this water delivery commitment are as follows:

(In millions)		
2024	$	7
2025		7
2026		7
2027		7
2028		7
Thereafter		11
	$	46

As of December 31, 2023, the Company had accrued a liability of $21 million associated with this commitment, representing the present value of estimated amounts payable due to insufficient forecasted delivery volumes.

Lease Commitments

The Company has operating leases for office space, surface use agreements, compressor services, electric hydraulic fracturing services, and other leases. The leases have remaining terms ranging from one month to 22 years, including options to extend leases that the Company is reasonably certain to exercise. During the year ended December 31, 2023, the Company recognized operating lease cost and variable lease cost of $127 million and $139 million, respectively. During the year ended

December 31, 2022, the Company recognized operating lease cost and variable lease cost of $104 million and $9 million, respectively.

Short-term leases. The Company leases drilling rigs, fracturing and other equipment under lease terms ranging from 30 days to one year. Lease cost of $777 million and $265 million was recognized on short-term leases during the year ended December 31, 2023 and 2022, respectively. Certain lease costs are capitalized and included in properties and equipment, net in the Consolidated Balance Sheet because they relate to drilling and completion activities, while other costs are expensed because they relate to production and administrative activities.

As of December 31, 2023, the Company's future undiscounted minimum cash payment obligations for its operating lease liabilities are as follows:

(In millions)	**Year Ending December 31,**
2024	$ 128
2025	113
2026	53
2027	22
2028	19
Thereafter	54
Total undiscounted future lease payments	389
Present value adjustment	(36)
Net operating lease liabilities	$ 353

As of December 31, 2023, the Company's future undiscounted minimum cash payment obligations for its financing lease liabilities are as follows:

(In millions)	**Year Ending December 31,**
2024	$ 7
2025	5
Total undiscounted future lease payments	12
Present value adjustment	—
Net financing lease liabilities	$ 12

Supplemental cash flow information related to leases was as follows:

	Year Ended December 31,	
(In millions)	**2023**	**2022**
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 132	$ 104
Financing cash flows from financing leases	$ 6	$ 6

Information regarding the weighted-average remaining lease term and the weighted-average discount rate for operating and financing leases is summarized below:

	December 31,	
	2023	**2022**
Weighted-average remaining lease term (in years)		
Operating leases	4.5	4.6
Financing leases	1.7	2.7
Weighted-average discount rate		
Operating leases	3.9 %	3.3 %
Financing leases	2.1 %	2.4 %

Legal Matters

Securities Litigation

In October 2020, a class action lawsuit styled Delaware County Emp. Ret. Sys. v. Cabot Oil and Gas Corp., et. al. (U.S. District Court, Middle District of Pennsylvania), was filed against the Company, Dan O. Dinges, its then-Chief Executive Officer, and Scott C. Schroeder, its then-Chief Financial Officer, alleging that the Company made misleading statements in its periodic filings with the SEC in violation of Section 10(b) and Section 20 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). The plaintiffs allege misstatements in the Company’s public filings and disclosures over a number of years relating to its potential liability for alleged environmental violations in Pennsylvania. The plaintiffs allege that such misstatements caused a decline in the price of the Company’s common stock when it disclosed in its Quarterly Report on Form 10-Q for the quarterly period ending June 30, 2019 two notices of violations from the Pennsylvania Department of Environmental Protection and an additional decline when it disclosed on June 15, 2020 the criminal charges brought by the Office of the Attorney General of the Commonwealth of Pennsylvania related to alleged violations of the Pennsylvania Clean Streams Law, which prohibits discharge of industrial wastes. The court appointed Delaware County Employees Retirement System to represent the purported class on February 3, 2021. In April 2021, the complaint was amended to include Phillip L. Stalnaker, the Company’s then-Senior Vice President of Operations, as a defendant. The plaintiffs seek monetary damages, interest and attorney’s fees.

Also in October 2020, a stockholder derivative action styled Ezell v. Dinges, et. al. (U.S. District Court, Middle District of Pennsylvania) was filed against the Company, Messrs. Dinges and Schroeder and the Board of Directors of the Company serving at that time, for alleged securities violations under Section 10(b) and Section 21D of the Exchange Act arising from the same alleged misleading statements that form the basis of the class action lawsuit described above. In addition to the Exchange Act claims, the derivative actions also allege claims based on breaches of fiduciary duty and statutory contribution theories. In December 2020, the Ezell case was consolidated with a second derivative case filed in the U.S. District Court, Middle District of Pennsylvania with similar allegations. In January 2021, a third derivative case was filed in the U.S. District Court, Middle District of Pennsylvania with substantially similar allegations and it too was consolidated with the Ezell case in February 2021.

On February 25, 2021, the Company filed a motion to transfer the class action lawsuit to the U.S. District Court for the Southern District of Texas, in Houston, Texas, where its headquarters are located. On June 11, 2021, the Company filed a motion to dismiss the class action lawsuit on the basis that the plaintiffs’ allegations do not meet the requirements for pleading a claim under Section 10(b) or Section 20 of the Exchange Act. On June 22, 2021, the motion to transfer the class action lawsuit to the Southern District of Texas was granted. Pursuant to the prior agreement of the parties, the consolidated derivative case discussed in the preceding paragraph was also transferred to the Southern District of Texas on July 12, 2021. Subsequently, an additional stockholder derivative action styled Treppel Family Trust U/A 08/18/18 Lawrence A. Treppel and Geri D. Treppel for the benefit of Geri D. Treppel and Larry A. Treppel v. Dinges, et al. (U.S. District Court, Southern District of Texas, Houston Division), asserting substantially similar Delaware common law claims as in the existing derivative cases, was filed in the Southern District of Texas and consolidated with the existing consolidated derivative cases. On January 12, 2022, the U.S. District Court for the Southern District of Texas granted the Company’s motion to dismiss the class action lawsuit but allowed the plaintiffs to file an amended complaint. The class action plaintiffs filed their amended complaint on February 11, 2022. The Company filed a motion to dismiss the amended class action complaint on March 10, 2022. On August 10, 2022, the U.S. District Court for the Southern District of Texas granted in part and denied in part the Company’s motion to dismiss the amended class action complaint, dismissing certain claims with prejudice but allowing certain claims to proceed. The Company filed its answer to the amended class action complaint on September 14, 2022. The class action case is presently in the discovery stage. On September 27, 2023, the U.S. District Court for the Southern District of Texas granted the class action plaintiffs’ motion for class certification. The Company filed a petition on October 11, 2023, for leave to appeal the class certification order, which the U.S. Court of Appeals for the Fifth Circuit denied on November 17, 2023. On October 20, 2023, the class action plaintiffs filed a motion for leave to amend the class action complaint to assert additional claims, including claims regarding the Company’s 2018 and 2019 production guidance. On January 8, 2024, the U.S. District Court for the Southern District of Texas granted plaintiffs’ motion to add additional claims regarding the Company’s 2019 production guidance and certain environmental disclosures made on or after July 26, 2019, but dismissed plaintiffs’ proposed new claims over the 2018 production guidance as barred by the applicable statute of repose. The Company intends to vigorously defend the class action.

With respect to the consolidated derivative cases, on April 1, 2022, the U.S. District Court for the Southern District of Texas granted the Company’s motion to dismiss such consolidated derivative cases but allowed the plaintiffs to file an amended complaint. The derivative plaintiffs filed their third amended complaint on May 16, 2022. The Company filed its motion to dismiss such amended complaint on June 24, 2022, and filed its reply in support of such motion to dismiss on September 4, 2022. On March 27, 2023, the U.S. District Court for the Southern District of Texas denied the motion to dismiss the derivative case as moot and ordered the Company to file a renewed motion to dismiss addressing certain issues regarding the impact of the class action litigation on the derivative case. The Company filed its renewed motion to dismiss on April 28, 2023. On January 2, 2024, the Court issued an order and final judgment granting the Company's motion to dismiss and dismissing the derivative case with prejudice. The derivative plaintiffs filed a notice of appeal regarding the final judgement on February 1, 2024. The Company intends to vigorously defend any further proceedings in the derivative lawsuit.

Other Legal Matters

The Company is a defendant in various other legal proceedings arising in the normal course of business. All known liabilities are accrued when management determines they are probable and the potential loss is estimable. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company's financial position, results of operations or cash flows.

Contingency Reserves

When deemed necessary, the Company establishes 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 that the Company could incur additional losses with respect to those matters for which reserves have been established. The Company believes that any such amount above the amounts accrued would not be material to the Consolidated Financial Statements. Future changes in facts and circumstances not currently known or foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

9. Revenue Recognition

Disaggregation of Revenue

The following table presents revenues from contracts with customers disaggregated by product:

	Year Ended December 31,		
(In millions)	2023	2022	2021
OPERATING REVENUES			
Natural gas	$ 2,292	$ 5,469	$ 2,798
Oil	2,667	3,016	616
NGL	644	964	243
Other	81	65	13
	$ 5,684	$ 9,514	$ 3,670

All of the Company's revenues from contracts with customers represent products transferred at a point in time as control is transferred to the customer and generated in the U.S.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company’s product sales contracts are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

As of December 31, 2023, the Company has $6.6 billion of unsatisfied performance obligations related to natural gas sales that have a fixed pricing component and a contract term greater than one year. The Company expects to recognize these obligations over the next 15 years.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $723 million and $1.1 billion as of December 31, 2023 and 2022, respectively, and are reported in accounts receivable, net in the Consolidated Balance Sheet. As of December 31, 2023 and 2022, the Company had no assets or liabilities related to its revenue contracts, including no upfront payments or rights to deficiency payments.

10. Income Taxes

Income tax expense is summarized as follows:

(In millions)	Year Ended December 31, 2023	2022	2021
Current			
Federal	$ 387	$ 791	$ 207
State	42	78	11
	429	869	218
Deferred			
Federal	52	217	119
State	22	18	7
	74	235	126
Income tax expense	$ 503	$ 1,104	$ 344

Income tax expense was different than the amounts computed by applying the statutory federal income tax rate as follows:

	Year Ended December 31,					
	2023		2022		2021	
(In millions, except rates)	Amount	Rate	Amount	Rate	Amount	Rate
Computed "expected" federal income tax	$ 447	21.00 %	$ 1,085	21.00 %	$ 315	21.00 %
State income tax, net of federal income tax benefit	29	1.35 %	93	1.80 %	24	1.59 %
Deferred tax adjustment related to change in overall state tax rate	16	0.73 %	(23)	(0.45)%	(7)	(0.46)%
Valuation allowance	3	0.13 %	(66)	(1.28)%	3	0.22 %
Excess executive compensation	11	0.50 %	10	0.20 %	15	1.03 %
Reserve on uncertain tax positions	6	0.31 %	6	0.12 %	1	0.05 %
Tax credits generated	(14)	(0.65)%	(34)	(0.66)%	(6)	(0.39)%
Other, net	5	0.27 %	33	0.62 %	(1)	(0.14)%
Income tax expense	$ 503	23.64 %	$ 1,104	21.35 %	$ 344	22.90 %

In 2023, the Company's overall effective tax rate increased compared to 2022, primarily due to tax expenses recorded in 2023 compared to tax benefits recorded in 2022 from the release of valuation allowances primarily associated with state net operating loss carryforwards and deferred tax adjustments related to changes in the overall state tax rate. The overall effective tax rate decreased in 2022 compared to 2021, primarily due to tax benefits recorded in 2022 compared to 2021 from the release of valuation allowances primarily associated with state net operating loss carryforwards, a decrease in the non-deductible excess executive compensation paid in 2022 compared to 2021, and greater research and development tax credit benefits recorded in 2022 compared to 2021 related to amended prior-year returns.

The composition of net deferred tax liabilities is as follows:

(In millions)	December 31, 2023	December 31, 2022
Deferred Tax Assets		
Net operating losses	$ 173	$ 196
Incentive compensation	47	24
Deferred compensation	5	30
Capital loss carryforward	16	16
Leases	96	96
Other	42	38
Less: valuation allowance	(114)	(110)
Total	265	290
Deferred Tax Liabilities		
Properties and equipment	3,558	3,498
Leases	98	97
Derivative instruments	21	33
Other	1	1
Total	3,678	3,629
Net deferred tax liabilities	$ 3,413	$ 3,339

At December 31, 2023, the Company had federal net operating loss carryforwards of approximately $383 million, of which $318 million is subject to expiration in years 2035 through 2037, and of which $65 million does not expire. The Company had a valuation allowance on $38 million of the federal net operating loss carryforwards, but believes the remaining $345 million will be fully utilized prior to expiration. The Company had gross state net operating loss carryforwards of $2.7 billion at December 31, 2023, primarily expiring between 2023 and 2043, with all but $151 million covered by a valuation allowance. The Company had a capital loss carryforward of $71 million, which can only be used to offset future capital gains, and expires in 2024. Accordingly, all but $6 million has been offset with a valuation allowance. The Company also had enhanced oil recovery credits of $4 million at December 31, 2023 that are fully offset by valuation allowances.

As of December 31, 2023, the Company had $8 million of valuation allowances on the deferred tax benefits related to federal net operating loss carryforwards, $87 million of valuation allowances on the deferred tax benefits related to state net operating loss carryforwards, $15 million of valuation allowances on the deferred tax benefits related to capital loss carryforwards, and $4 million of valuation allowances on the deferred tax benefits related to enhanced oil recovery credits. The Company believes it is more likely than not that the remainder of its deferred tax benefits will be utilized prior to their expiration.

Unrecognized Tax Benefits

A reconciliation of unrecognized tax benefits is as follows:

(In millions)	Year Ended December 31, 2023	2022	2021
Balance at beginning of period	$ 13	$ 7	$ 6
Additions for tax positions of current period	4	1	1
Additions for tax positions of prior periods	3	5	—
Balance at end of period	$ 20	$ 13	$ 7

During 2023, the Company recorded a $4 million reserve for unrecognized tax benefits related to estimated current year research and development tax credits. In addition, the Company also recorded a $3 million reserve for unrecognized tax benefits related to research and development credits taken on the 2022 tax return. As of December 31, 2023, the Company's overall net reserve for unrecognized tax positions was $20 million, with a $2 million liability for accrued interest on the uncertain tax positions. The Company believes that if recognized, the net tax benefit of $20 million would not have a material effect on the Company’s effective tax rate.

The Company files income tax returns in the U.S. federal, various states and other jurisdictions. The Company is no longer subject to examinations by state authorities before 2012 or by federal authorities before 2017. The Company believes that appropriate provisions have been made for all jurisdictions and all open years, and that any assessment on these filings will not have a material impact on the Company’s financial position, results of operations or cash flows.

Recent U.S. Tax Legislation

On August 16, 2022, the Inflation Reduction Act (“IRA”) was signed into law pursuant to the budget reconciliation process. The IRA introduced a new 15 percent corporate alternative minimum tax (“CAMT”), effective for tax years beginning after December 31, 2022, on the adjusted financial statement income (“AFSI”) of corporations with average AFSI exceeding $1 billion over a three-year testing period. The IRA also introduced an excise tax of one percent on the fair market value of certain public company stock repurchases made after December 31, 2022. Based on the current CAMT guidance available, the Company is an “applicable corporation” beginning in 2023, but is not expecting to owe any additional tax under the CAMT for 2023.

11. Employee Benefit Plans

Postretirement Benefits

The Company provides health care benefits to certain former employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. The health care plans are contributory, with participants’ contributions adjusted annually. Most employees that participate in the plan become eligible for these benefits when they meet certain age and service requirements at retirement.

At the end of 2023 and 2022, the Company provided postretirement benefits to 290 and 320 retirees and their dependents, respectively.

During 2022, the Company amended its postretirement plans to phase out all postretirement benefits and freeze future participation in the plan. Certain employees were grandfathered under the plan amendment and remain eligible for future participation in the pre-65 plan upon their retirement based on certain age and years of service criteria, while the post-65 benefit for all plan participants that reach the age of 65 after December 31, 2022, including current retirees participating the pre-65 plan, will be eliminated. Existing retirees participating in both the pre-65 and post-65 plans prior to December 31, 2022 will continue to receive benefits under the plan until the age of 65 in the case of the pre-65 participants, or voluntary termination of benefits or by death in the case of post-65 participants.

Retirement Savings Plan

The Company has a Retirement Savings Plan (“RSP”), which is a defined contribution plan. The Company matches a portion of employees’ contributions in cash. Participation in the RSP is voluntary and all employees of the Company are eligible to participate. The Company matches employee contributions dollar-for-dollar, up to the maximum Internal

Revenue Service (“IRS”) limit, on the first six percent of an employee’s pre-tax earnings. The RSP also provides for discretionary contributions in an amount equal to 10 percent of an eligible plan participant’s salary and bonus.

In connection with the Merger, the Company assumed the Cimarex Energy Co. 401(k) Plan (the “401(k) Plan”) with respect to Cimarex employees. The Company maintained this plan throughout the integration process and terminated this plan effective December 31, 2022, with all legacy Cimarex employees becoming eligible for the Company’s RSP effective January 1, 2023.

During the years ended December 31, 2023, 2022 and 2021, the Company made aggregate contributions to the RSP and 401(k) Plan of $19 million, $12 million and $7 million, respectively, which are included in G&A expense in the Consolidated Statement of Operations. The Company’s common stock was an investment option within the RSP and the 401(k) Plan. Effective December 31, 2022, investment in the Company’s common stock is no longer an option.

Deferred Compensation Plans

The Company has deferred compensation plans which are available to officers and select employees and act as a supplement to the RSP. The Internal Revenue Code does not cap the amount of compensation that may be taken into account for purposes of determining contributions to the deferred compensation plans and does not impose limitations on the amount of contributions to the deferred compensation plans. At the present time, the Company anticipates making a contribution to the deferred compensation plans on behalf of a participant in the event that Internal Revenue Code limitations cause a participant to receive less than the Company contribution under the RSP.

The assets of the deferred compensation plans are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company.

Under the deferred compensation plans, the participants direct the deemed investment of amounts credited to their accounts. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company’s common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded and have market prices that are readily available. The Company’s common stock is no longer an investment option in the deferred compensation plan effective December 31, 2022. All outstanding Coterra shares previously held in the trust represented vested performance share awards that were previously deferred into the rabbi trust and were liquidated in 2023. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments.

The market value of the trust assets, excluding the Company’s common stock, was $33 million and $43 million at December 31, 2023 and 2022, respectively, and is included in other assets in the Consolidated Balance Sheet. Related liabilities, including the Company’s common stock, totaled $33 million and $55 million at December 31, 2023 and 2022, respectively, and are included in other liabilities in the Consolidated Balance Sheet. Increases (decreases) in the fair value of the Company’s common stock prior to disposition, and the increase in value of the Company’s stock upon liquidation in 2023 were recognized as compensation expense (benefit) in G&A expense in the Consolidated Statement of Operations. There is no impact on earnings or earnings per share from the changes in market value of the other deferred compensation plan assets because the changes in market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants.

The Company made contributions to the deferred compensation plans of $3 million, $1 million and $20 million in 2023, 2022 and 2021, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations.

12. Capital Stock

Issuance of Common Stock

Following the effectiveness of the Merger, on October 1, 2021, the Company issued approximately 408.2 million shares of its common stock to Cimarex stockholders under the terms of the Merger Agreement.

Dividends

Common Stock

In February 2023, the Company’s Board of Directors approved an increase in the base quarterly dividend from $0.15 per share to $0.20 per share beginning in the first quarter of 2023.

The following table summarizes the dividends the Company has paid on its common stock during 2023, 2022 and 2021:

	Rate per share			
	Base	Variable	Total	Total Dividends Paid (In millions)
2023:				
First quarter	$ 0.20	$ 0.37	$ 0.57	$ 438
Second quarter	0.20	—	0.20	153
Third quarter	0.20	—	0.20	153
Fourth quarter	0.20	—	0.20	151
Total year-to-date	$ 0.80	$ 0.37	$ 1.17	$ 895
2022:				
First quarter	$ 0.15	$ 0.41	$ 0.56	$ 455
Second quarter	0.15	0.45	0.60	484
Third quarter	0.15	0.50	0.65	519
Fourth quarter	0.15	0.53	0.68	533
Total year-to-date	$ 0.60	$ 1.89	$ 2.49	$ 1,991
2021:				
First quarter	$ 0.10	$ —	$ 0.10	$ 40
Second quarter	0.11	—	0.11	44
Third quarter	0.11	—	0.11	44
Fourth quarter[1]	0.13	0.67	0.80	651
Total year-to-date	$ 0.45	$ 0.67	$ 1.12	$ 779

(1) Includes a special dividend of $0.50 per share on the Company's common stock that was paid in connection with the completion of the Merger.

Subsequent Event. In February 2024, the Company's Board of Directors approved an increase in our base quarterly dividend from $0.20 per share to $0.21 per share beginning in the first quarter of 2024, and approved a quarterly base dividend of $0.21 per share.

Treasury Stock

In February 2023, the Company's Board of Directors terminated the previously authorized share repurchase program and approved a new share repurchase program which authorizes the purchase of up to $2.0 billion of the Company's common stock. During 2023, the Company repurchased and retired 17 million shares of common stock for $418 million under its new repurchase program. As of December 31, 2023, the Company's had $1.6 billion remaining under its current share repurchase program.

In February 2022, the Company’s Board of Directors authorized a share repurchase program up to $1.25 billion of the Company’s common stock in the open market or in negotiated transactions, which was fully executed at December 31, 2022.

During 2023, 2022 and 2021, the Company withheld and retired 332,634, 320,236 and 125,067 shares of common stock, respectively, valued at $9 million, $9 million and $3 million, respectively, related to shares withheld for taxes upon the vesting of certain restricted stock awards.

In December 2022, the Company’s Board of Directors authorized the retirement of the Company’s common stock held in treasury and as of December 31, 2022, and provided that prospectively, share repurchases, and shares withheld for the vesting of stock awards will be retired in the period in which they are repurchased or withheld. Accordingly, as of December 31, 2023 and 2022, there were no common shares held in treasury stock on the Consolidated Balance Sheet.

Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the common stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures and its future business prospects. None of the senior note or credit agreements in place have restricted payment provisions or other provisions which currently limit the Company's ability to pay dividends.

Cimarex Redeemable Preferred Stock

In October 2021, in connection with the Merger, the Company assumed the obligations associated with Cimarex's preferred stock, par value $0.01 per share, designated as 8 1/8% Series A Cumulative Perpetual Convertible Preferred Stock (the "Preferred Stock"). The Preferred Stock was originally issued by Cimarex and remains on the Cimarex balance sheet after the Merger. The Company accounts for the Preferred Stock as a non-controlling interest, which is immaterial for reporting purposes.

During the years ended December 31, 2023 and 2002, holders of a portion of the Preferred Stock elected to convert their Preferred Stock into Coterra common stock and cash as follows:

	2023	2022
Preferred stock converted into Coterra common stock	2,000	21,900
Coterra common stock issued	79,285	809,846
Cash paid for conversion (in millions)	$ 1	$ 10
Book value of preferred shares at conversion (in millions)	$ 3	$ 39

Upon conversion of the Preferred Stock, the excess of carrying value over cash paid was credited to additional paid-in capital in the Consolidated Balance Sheet. There was no gain or loss recognized on the transactions as the shares were converted in accordance with the original terms of the Certificate of Designations for the Preferred Stock. At December 31, 2023, there were 4,265 shares of Preferred Stock outstanding with a carrying value of $8 million.

13. Stock-Based Compensation

Incentive Plan

On May 4, 2023, the Company's stockholders approved the Coterra Energy Inc. 2023 Equity Incentive Plan (the "2023 Plan") which replaced the then-existing Cabot Oil & Gas Corporation 2014 Incentive Plan (the "2014 Plan") and Cimarex Energy Co. Amended and Restated 2019 Equity Incentive Plan (the "2019 Plan"). Under the 2023 Plan, permitted awards include, but are not limited to, options, stock appreciation rights, restricted stock, restricted stock units, performance stock units and other cash and stock-based awards. A total of 22.95 million shares of common stock may be issued under the 2023 Plan. The 2023 Plan expires on February 21, 2033. No additional awards may be granted under the 2014 Plan or the 2019 Plan on or after May 4, 2023. Awards outstanding under any of the

Company’s prior plans will remain outstanding and vest in accordance with their original terms and conditions. At December 31, 2023, approximately 21.1 million shares are available for issuance under the 2023 Plan.

Table of Contents

Stock-based compensation expense of awards issued under the Company’s incentive plans, and the income tax benefit of awards vested and exercised, are as follows:

(In millions)	Year Ended December 31, 2023	2022	2021
Restricted stock units - employees and non-employee directors	$ 37	$ 38	$ 7
Restricted stock awards	14	24	7
Performance share awards [1]	15	22	42
Deferred performance shares [2]	(7)	2	1
Total stock-based compensation expense	$ 59	$ 86	$ 57
Income tax benefit	$ 7	$ 20	$ 24

(1) In accordance with the Merger Agreement, the Company recognized approximately $18 million of stock-based compensation expense in the fourth quarter of 2021 associated with the acceleration of vesting of certain performance share awards. In the third quarter of 2022, the Company recognized approximately $7 million of stock-based compensation expense associated with the acceleration of vesting of certain employee performance awards.

(2) During 2023, 495,774 shares of the Company’s common stock representing vested performance share awards previously deferred into the deferred compensation plan were sold and invested in other investment options. The sale of the Company’s common stock resulted in a $7 million decrease to the deferred compensation liability and a corresponding decrease in stock-based compensation expense. Refer to Note 11 for further discussion of the Company’s deferred compensation plan.

Restricted Stock Units - Employees

Restricted stock units are granted to employees of the Company. The fair value of restricted stock unit grants is based on the closing stock price on the grant date. Restricted stock units generally vest at the end of a three year service period. The restricted stock units are settled in shares of the Company’s common stock on the vesting date.

For awards that vest at the end of the service period, expense is recognized ratably using a straight-line approach over the service period. For most restricted stock units, vesting is dependent upon the employees’ continued service with the Company, with the exception of employment termination due to death, disability or, if applicable, retirement. If retirement protection is included in the grant award, the Company accelerates the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company’s stock-based compensation programs.

The Company used an annual forfeiture rate assumption ranging from zero to five percent for purposes of recognizing stock-based compensation expense for these restricted stock units. The annual forfeiture rates were based on the Company’s actual forfeiture history and expectations for this type of award.

The following table is a summary of restricted stock unit award activity:

	Year Ended December 31, 2023	
	Shares	Weighted-Average Grant Date Fair Value per Unit
Outstanding at beginning of period	3,188,144	$ 23.47
Granted	2,381,117	26.12
Vested	(315,094)	22.33
Forfeited	(229,252)	25.05
Outstanding at end of period	5,024,915	$ 24.73

The weighted-average grant date fair value per unit granted during 2023, 2022 and 2021 was $26.12, $24.81 and $20.83 respectively.

Restricted Stock Units - Non-Employee Directors

Restricted stock units are granted to non-employee directors of the Company. The fair value of the restricted stock units is based on the closing stock price on the grant date. Awards that were granted prior to 2022 vested on the grant date, compensation expense was recorded immediately, and the shares of the Company's common stock will be issued when the director ceases to be a director of the Company. The 2022 grants vested in 2023, compensation expense was recognized ratably over the service period and Company stock was issued on the vesting date. The 2023 grants will vest, and Company shares will be issued on May 1, 2024 or upon the director's separation from the Company, as applicable, and accordingly the Company recognized compensation expense immediately.

The Company assumed a zero percent annual forfeiture rate for purposes of recognizing stock-based compensation expense for these restricted stock units, based on the Company's actual forfeiture history and expectations for this type of award.

The following table is a summary of restricted stock unit award activity:

	Year Ended December 31, 2023		
	Shares		Weighted-Average Grant Date Fair Value per Unit
Outstanding at beginning of period	291,370	$	22.72
Granted	73,593		24.46
Vested	(45,472)		35.19
Outstanding at end of period	319,491	$	21.34

The weighted-average grant date fair value per unit granted during 2023 and 2022 and 2021 was $24.46, $35.19 and $18.51, respectively.

Restricted Stock Awards

On October 1, 2021, the Company granted 3,364,354 shares of restricted stock, with a grant date value of $22.25 per share. These awards were replacement awards granted to Cimarex employees as provided under the Merger Agreement. The fair value of these awards was measured based on the closing stock price on the closing date of the Merger (grant date). Approximately $22 million of the grant date value was recognized as merger consideration and the remaining fair value will be recognized as stock-based compensation expense over the respective vesting periods. The remaining outstanding awards are expected to vest in 2024.

The Company used an annual forfeiture rate assumption of ranging from zero to 15 percent for purposes of recognizing stock-based compensation expense for restricted stock awards. The annual forfeiture rates were based on the Company's actual forfeiture history for this type of award to various employee groups.

The following table is a summary of restricted stock award activity:

	Year Ended December 31, 2023	
	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	2,068,974	$ 22.25
Vested	(845,318)	22.25
Forfeited	(127,060)	22.25
Outstanding at end of period	1,096,596	$ 22.25

Performance Share Awards

The Company grants performance share awards that are based on performance conditions measured against the Company's internal performance metrics ("Employee Performance Share Awards") or based on the Company's performance relative to a predetermined peer group and industry-related indices ("TSR Performance Share Awards"). The performance period for these awards generally commences on February 1 of the respective year in which the award was granted and extends over a three-year performance period. For most performance share awards, vesting is dependent upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or, if applicable, retirement. For all outstanding performance share awards, the Company did not use an annual forfeiture rate for purposes of recognizing stock-based compensation expense for its performance share awards. The annual forfeiture rate assumption was based on the Company's actual forfeiture history or expectations for this type of award.

Performance Share Awards Based on Internal Performance Metrics

The fair value of performance share award grants based on internal performance metrics is based on the closing stock price on the grant date. Each performance share award represents the right to receive up to 100 percent of the award in shares of common stock.

Employee Performance Share Awards. The Employee Performance Share Awards vest at the end of the three-year performance period and the performance metric are set by the Company's Compensation Committee. An employee will earn 100 percent of the award on the third anniversary, provided that the Company averages $100 million or more of operating cash flow during the three-year performance period. Based on the Company's probability assessment at December 31, 2023, it is considered probable that all of the criteria for these awards will be met. The remaining outstanding awards are expected to vest in 2024.

The following table is a summary of activity for Employee Performance Share Awards:

	Year Ended December 31, 2023	
	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	73,314	$ 20.46
Outstanding at end of period	73,314	$ 20.46

Performance Share Awards Based on Market Conditions

These awards have both an equity and liability component, with the right to receive up to the first 100 percent of the award in shares of common stock and the right to receive up to an additional 100 percent of the value of the award in excess of the equity component in cash. The equity portion of these awards is valued on the grant date and is not marked to market, while the liability portion of the awards is valued as of the end of each reporting period on a mark-to-market basis. The Company calculates the fair value of the equity and liability portions of the awards using a Monte Carlo simulation model.

TSR Performance Share Awards. The TSR Performance Share Awards granted are earned, or not earned, based on the comparative performance of the Company's common stock measured against a predetermined group of companies in the Company's peer group and certain industry-related indices over a three-year performance period. The Company's TSR Performance Share Awards also include a feature that will reduce the potential cash component of the award if the actual performance is negative over the three-year period and the base calculation indicates an above-target payout.

The following table is a summary of activity for the TSR Performance Share Awards:

	Year Ended December 31, 2023	
	Shares	Weighted-Average Grant Date Fair Value per Unit (1)
Outstanding at beginning of period	1,161,599	$ 17.89
Granted	658,202	17.55
Forfeited	(121,206)	17.40
Outstanding at end of period	1,698,595	$ 17.79

(1) The grant date fair value figures in this table represent the fair value of the equity component of the performance share awards.

The following table reflects certain balance sheet information of outstanding TSR Awards:

	December 31,	
(In millions)	2023	2022
Other current liabilities	$ —	$ —
Other non-current liabilities	$ 7	3

The following table reflects certain cash payments related to the vesting of TSR Awards:

	Year Ended December 31,		
(In millions)	2023	2022	2021
Cash payments for TSR awards	$ —	$ —	$ —

The following assumptions were used to determine the grant date fair value of the equity component of the TSR Performance Share Awards for the respective periods:

	Year Ended December 31,		
	2023	2022	2021
Fair value per performance share award granted during the period	$17.18 - $20.20	$ 9.01	$ 16.07
Assumptions			
Stock price volatility	40.6% - 44.8%	42.6 %	39.8 %
Risk free rate of return	4.4% - 4.8%	4.4 %	0.2 %

The following assumptions were used to determine the fair value of the liability component of the TSR Performance Share Awards for the respective periods:

	December 31,		
	2023	**2022**	**2021**
Fair value per performance share award at the end of the period	$7.57 - $10.67	$ 14.92	$—
Assumptions			
Stock price volatility	29.1% - 38.8%	42.6 %	—%
Risk free rate of return	4.2% - 4.7%	4.4 %	—%

The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the U.S. Treasury within the expected term as measured on the grant date.

Other Information

The following table reflects the aggregate fair value of awards and units that vested during the respective period:

	December 31,		
(In millions)	2023	2022	2021
Restricted stock units - employees and non-employee directors	$ 9	$ 9	$ 11
Restricted stock awards	22	22	7
Performance share awards	—	45	84
	$ 31	$ 76	$ 102

The following table reflects the unrecognized stock-based compensation and the related weighted-average recognition period associated with the unvested awards and units as of December 31, 2023:

	Unrecognized Stock-Based Compensation (In Millions)	Weighted-Average Period For Recognition (Years)
Restricted stock units - employees and non-employee directors	$ 70	1.7
Restricted stock awards	6	0.8
Performance share awards	14	1.3
	$ 90	

Stock Option Awards

On October 1, 2021, the Company granted stock option awards to purchase 1,577,554 shares of the Company’s common stock with exercise prices ranging from $8.47 to $28.72 per share. These awards were replacement awards granted to Cimarex employees as provided under the Merger Agreement and were fully vested on the closing date of the Merger. The grant date fair value of approximately $14 million was recognized as merger consideration and, accordingly, no compensation expense will be recognized by the Company related to these awards, as there is no future service requirement for the holders of these awards.

The following table is a summary of activity for the Stock Option Awards:

	Year Ended December 31, 2023	
	Shares	Weighted-Average Strike Price
Outstanding at beginning of period	536,609	$ 18.08
Exercised	(113,500)	13.82
Forfeited or Expired	(118,226)	28.42
Outstanding at end of period[1]	304,883	$ 15.66
Exercisable at end of period[1]	304,883	$ 15.66

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the stock option. The aggregate intrinsic value of stock options outstanding and exercisable at December 31, 2023 was $3 million and $3 million, respectively. The weighted-average remaining contractual term is 2.1 years.

Deferred Performance Shares

During 2023, 495,774 shares of the Company’s common stock representing vested performance share awards previously deferred into the deferred compensation plan, were sold and invested in other investment options. The sale of the Company’s common stock resulted in a $7 million decrease to the deferred compensation liability and a corresponding decrease in stock-based compensation expense.

Table of Contents

14. Earnings per Common Share

Basic earnings per share ("EPS") is computed by dividing net income available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted EPS is similarly calculated except that the common shares outstanding for the period is increased using the treasury stock and as-if-converted methods to reflect the potential dilution that could occur if outstanding stock awards were vested or exercised at the end of the applicable period. Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted income or loss per share as their impact would be anti-dilutive.

The following is a calculation of basic and diluted net earnings per common share under the two-class method:

	Year Ended December 31,		
(In millions except per share amounts)	2023	2022	2021
Income (Numerator)			
Net income	$ 1,625	$ 4,065	$ 1,158
Less: dividends attributable to participating securities	(5)	(7)	(2)
Less: Cimarex redeemable preferred stock dividends	—	(1)	(1)
Net income available to common stockholders	$ 1,620	$ 4,057	$ 1,155
Shares (Denominator)			
Weighted average shares - Basic	756	796	503
Dilution effect of stock awards at end of period	4	3	1
Weighted average shares - Diluted	760	799	504
Earnings per share:			
Basic	$ 2.14	$ 5.09	$ 2.30
Diluted	$ 2.13	$ 5.08	$ 2.29

The following is a calculation of weighted-average shares excluded from diluted EPS due to the anti-dilutive effect:

	Year Ended December 31,		
(In millions)	2023	2022	2021
Weighted-average stock awards excluded from diluted EPS due to the anti-dilutive effect calculated using the treasury stock method	1	1	1

15. Restructuring Costs

During 2023, 2022 and 2021, the Company recognized $12 million, $52 million and $44 million, respectively, of restructuring costs that are primarily related to workforce reductions and associated severance benefits that were triggered by the Merger. The following table summarizes the Company's restructuring liabilities:

	Year Ended December 31,		
(In millions)	**2023**	**2022**	**2021**
Balance at beginning of period	$ 77	$ 43	$ —
Additions related to merger integration	12	52	44
Reductions related to severance payments	(42)	(18)	(1)
Balance at end of period	$ 47	$ 77	$ 43

Table of Contents

16. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In millions)	December 31, 2023	2022
Accounts receivable, net		
Trade accounts	$ 723	$ 1,067
Joint interest accounts	118	108
Other accounts	4	48
	845	1,223
Allowance for doubtful accounts	(2)	(2)
	$ 843	$ 1,221
Other assets		
Deferred compensation plan	$ 33	$ 43
Debt issuance cost	8	3
Derivative instruments	7	—
Operating lease right-of-use assets	337	382
Other accounts	82	36
	$ 467	$ 464
Accounts payable		
Trade accounts	$ 60	$ 27
Royalty and other owners	386	438
Accrued gathering, processing, and transportation	80	85
Accrued capital costs	165	148
Accrued lease operating costs	39	32
Taxes other than income	33	73
Other accounts	40	41
	$ 803	$ 844
Accrued liabilities		
Employee benefits	$ 70	$ 74
Taxes other than income	14	62
Restructuring liability	35	39
Operating lease liabilities	116	114
Financing lease liabilities	6	6
Other accounts	20	33
	$ 261	$ 328
Other liabilities		
Deferred compensation plan	$ 33	$ 55
Postretirement benefits	17	17
Operating lease liabilities	237	287
Financing lease liabilities	6	11
Restructuring liability	12	38
Other accounts	124	92
	$ 429	$ 500

17. Interest Expense

Interest expense is comprised of the following:

	Year Ended December 31,		
(In millions)	2023	2022	2021
Interest Expense			
Interest expense	$ 82	$ 110	$ 62
Debt premium amortization	(21)	(37)	(10)
Debt issuance cost amortization	3	4	3
Other	9	3	7
	$ 73	$ 80	$ 62

18. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	2023	2022	2021
Cash paid for interest and income taxes			
Interest	$ 84	$ 119	$ 81
Income taxes	388	983	184
Non-cash activity			
Retirement of treasury shares	$ 418	$ 3,085	$ —
Equity and replacement stock awards issued as consideration in the Merger	$ —	$ —	$ 9,120

COTERRA ENERGY INC.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserves

Proved reserves are based on estimates prepared by the Company in accordance with guidelines established by the SEC. Reserves definitions comply with definitions of Rule 4-10(a) of Regulation S-X promulgated by the SEC under the Securities Act.

Users of this information should be aware that the process of estimating quantities of “proved,” “proved developed” and “proved undeveloped” oil, natural gas and NGL reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure that reserves estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Preparation of Reserves Estimates

All of the Company’s reserves estimates are maintained by the Company’s internal Corporate Reservoir Engineering group, which is comprised of engineers and engineering analysts. The objectives and management of this group are separate from and independent of the exploration and production functions of the Company. The primary objective of the Company’s Corporate Reservoir Engineering group is to maintain accurate forecasts on all properties of the Company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.). In addition, the Corporate Reservoir Engineering group maintains a set of basic guidelines and procedures to ensure that critical checks and reviews of the reserves database are performed on a regular basis.

The Corporate Reservoir Engineering group is responsible for estimates of proved reserves. Corporate engineers interact with the exploration and production departments to ensure all appropriate available engineering and geologic data is taken into account prior to establishing or revising an estimate. The recommended revisions of the corporate engineers are reviewed with the Vice President - Corporate Reservoir Engineering and, after approval, entered into the reserves database by an engineering analyst. During the course of the year, the Corporate Reservoir Engineering group reviews their recommendations and updates with the Vice President and Chief Technology Officer for additional oversight and approval. From time to time, the Vice President and Chief Technology Officer also will confer with senior management, including the Chief Executive Officer, regarding reserves-related issues. Upon completion of the process, the estimated reserves are presented to senior management and the Board of Directors.

The Company’s Vice President and Chief Technology Officer is the technical person primarily responsible for overseeing the Company’s internal reserves estimation process and the Company’s Corporate Reservoir Engineering group. This individual graduated from the

University of Tulsa with a Bachelor of Science degree in Petroleum Engineering. He has held numerous engineering and management roles and has over 16 years of experience in oil and gas reservoir evaluation and is a member of the Society of Petroleum Engineers.

The Company utilizes various methods and technologies to estimate its proved reserves, including analysis of production performance, analogy, decline curve analysis, rate and pressure transient analysis, reservoir simulation, material balance calculations, volumetric calculations, and in some cases a combination of these methods.

Review of Estimates by Third-Party Engineers

The Company also engages independent petroleum engineering consulting firms as an additional confirmation of the reasonableness of its internal estimates.

During 2023 and 2022, estimates of net proved reserves representing greater than 90 percent of the total future net revenue discounted at 10 percent attributable to the Company’s proved reserves were subject to an independent evaluation performed by DeGolyer and MacNaughton.

During 2021, 100 percent of the Company’s estimates with respect to the Company’s Marcellus Shale reserves were audited by Miller and Lents, Ltd. (“Miller and Lents”), and estimates of the net reserves representing greater than 80 percent of the total future net revenue discounted at 10 percent attributable to the Company's remaining reserves, other than those in the Marcellus Shale, were subject to an independent evaluation performed by DeGolyer and MacNaughton.

In each of the respective periods, DeGolyer and MacNaughton and Miller and Lents each indicated that, based on their investigations and subject to the limitations described in their reserves letters, they believe the Company's estimates were, in the aggregate, reasonable. A copy of DeGolyer and MacNaughton's letter regarding the 2023 reserves estimate has been filed as an exhibit to this Annual Report on Form 10-K.

Qualifications of Third-Party Engineers

DeGolyer and MacNaughton's Executive Vice President is the technical person primarily responsible for the evaluation of the Company's proved reserves. He is a Registered Professional Engineer in the State of Texas with over 13 years of experience in oil and gas reservoir studies and reserves evaluations and 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. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists and petro-physicists; they do not own an interest in the Company's properties and are not retained on a contingent fee basis.

Estimated Quantities of Proved Oil and Gas Reserves

Estimates of total proved reserves at December 31, 2023, 2022 and 2021 were computed using the trailing 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month during the respective year.

No major discovery or other favorable or unfavorable event after December 31, 2023, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Table of Contents

The following tables illustrate the Company’s net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated, as estimated by the Company’s engineering staff. All reserves are located within the continental U.S.

	Oil (MBbl)	Natural Gas (Bcf)	NGLs (MBbl)	Total (MBoe)
December 31, 2020	15	13,672	—	2,278,636
Revision of prior estimates	10,837	(538)	16,797	(61,967)
Extensions, discoveries and other additions	2,633	973	6,100	170,988
Production	(8,150)	(911)	(7,104)	(167,113)
Purchases of reserves in place	184,094	1,699	204,822	672,038
December 31, 2021	189,429	14,895	220,615	2,892,582
Revision of prior estimates	14,594	(4,299)	35,162	(666,716)
Extensions, discoveries and other additions	69,118	1,602	69,862	405,972
Production	(31,926)	(1,024)	(28,697)	(231,342)
Sales of reserves in place	(1,460)	(1)	(177)	(1,830)
December 31, 2022	239,755	11,173	296,765	2,398,666
Revision of prior estimates	1,084	(414)	8,067	(59,970)
Extensions, discoveries and other additions	44,386	823	46,148	227,660
Production	(35,110)	(1,053)	(32,932)	(243,497)
Sales of reserves in place	(902)	(4)	(592)	(2,102)
December 31, 2023	249,213	10,525	317,456	2,320,757
Proved Developed Reserves				
December 31, 2020	15	8,608	—	1,434,714
December 31, 2021	153,010	10,691	193,598	2,128,439
December 31, 2022	168,649	8,543	224,706	1,817,140
December 31, 2023	173,392	8,590	234,306	1,839,219
Proved Undeveloped Reserves				
December 31, 2020	—	5,064	—	843,922
December 31, 2021	36,419	4,204	27,017	764,143
December 31, 2022	71,107	2,630	72,059	581,526
December 31, 2023	75,821	1,935	83,150	481,538

Year-end 2023 proved reserves decreased approximately three percent from year-end 2022 proved reserves to 2,321 MMBoe. Proved natural gas reserves were 10.5 Tcf, proved oil reserves were 249 MMBbls, and proved NGL reserves were 317 MMBbls. The Company’s reserves in the Marcellus Shale accounted for 60 percent of total proved reserves, the

Permian Basin accounted for 31 percent, and the remaining nine percent were in the Anadarko Basin.

During 2023, the Company added 228 MMBoe of proved reserves through extensions, discoveries, and other additions, which included 87 MMBoe in the Marcellus Shale, 102 MMBoe in the Permian Basin, and 39 MMBoe in the Anadarko Basin. The Company had net negative revisions of prior estimates of 60 MMBoe, which included an 83 MMBoe negative revision due to price, a 10 MMBoe negative revision due to increases in operating expenses, partially offset by a positive 33 MMBoe performance revision.

During 2022, the Company added 406 MMBoe of proved reserves through extensions, discoveries, and other additions, which included 191 MMBoe in the Marcellus Shale, 193 MMBoe in the Permian Basin, and 22 MMBoe in the Anadarko Basin. The Company had net negative revisions of prior estimates of 667 MMBoe, which included 571 MMBoe in downward performance revisions related to updated forecast parameters in the Marcellus Shale to account for a different decline behavior observed in bounded wells compared to unbounded wells. The net negative revisions also included 168 MMBoe associated with the removal of PUD reserves in the Marcellus Shale whose development is expected to be delayed beyond five years of initial booking. These negative revisions in the Marcellus Shale were partially offset by 32 MMBoe in positive performance revisions in the Permian Basin, 39 MMBoe in positive revisions related to upward price revisions, and 1 MMBoe in positive revisions related to decreases in operating expenses.

During 2021, the Company added 171 MMBoe of proved reserves through extensions, discoveries, and other additions, which were primarily in the Marcellus Shale. Additionally, the Company added 672 MMBoe from purchases of reserves in place related to the acquisition of Cimarex’s oil and gas properties in connection with the Merger. The reserves acquired were primarily related to the Wolfcamp Shale and Bone Spring in the Permian Basin and the Woodford Shale in the Anadarko Basin. The Company also had net negative revisions of 62 MMBoe, which was primarily due to a 97 MMBoe downward performance revision and a 6 MMBoe downward revision associated with PUD reclassifications as a result of the five-year limitation. These downward revisions were partially offset by a 42 MMBoe positive pricing and cost revision. The net downward performance revision of 97 MMBoe was primarily due to a 57 MMBoe performance revision related to certain proved developed reserves and a 40 MMBoe downward performance revision associated with PUD reserves.

Proved Undeveloped Reserves

At December 31, 2023, the Company had PUD reserves of 482 MMBoe, down 100 MMBoe, or 17 percent, from 582 MMBoe of PUD reserves at December 31, 2022. Future development plans are reflective of the current commodity price environment and have been established based on expected available cash flows from operations. By the end of 2024, the Company expects to complete substantially all the work necessary to convert its PUD reserves associated with wells that were drilled but uncompleted at December 31, 2023 to proved developed reserves. As of December 31, 2023 all PUD reserves are expected to be drilled and completed within five years of initial disclosure of these reserves. The following table is a reconciliation of the change in the Company’s PUD reserves (MMBoe):

	Year Ended December 31, 2023
Balance at beginning of period	582
Transfers to proved developed	(265)
Additions	190
Revision of prior estimates	(25)
Balance at end of period	482

During 2023, the Company invested $1.3 billion to develop and convert 33 percent of its 2022 PUD reserves to proved developed reserves. During 2022, the Company invested $945 million to develop and convert 37 percent of its 2021 PUD reserves to proved developed reserves. During 2021, the Company invested $565 million to develop and convert 31 percent of its 2020 PUD reserves to proved developed reserves.

During 2023, the Company’s 190 MMBoe of PUD reserves additions consisted of 79 MMBoe added in the Marcellus Shale, 72 MMBoe added in the Permian Basin, and 39 MMBoe added in the Anadarko Basin. At December 31, 2023, 48 percent of the Company’s PUD reserves were in the Marcellus Shale, 42 percent were in the Permian Basin and the remaining 10 percent were in the Anadarko Basin.

During 2023, the Company had a net negative PUD reserves revision of 25 MMBoe, of which, 30 MMBoe is due to the removal of PUD reserves in the Marcellus Shale whose development is expected to be delayed beyond five years from the initial date of booking due to the Company’s updated development plans, which resulted in changes to the timing of capital investments. This negative revision was partially offset by a 5 MMBoe positive revision to PUD forecasts in the Marcellus Shale and Permian Basin due to better than expected well performance compared to previous proved reserves estimates.

Capitalized Costs Relating to Oil and Gas Producing Activities

Capitalized costs relating to oil and gas producing activities and related accumulated DD&A were as follows:

	December 31,		
(In millions)	2023	2022	2021
Aggregate capitalized costs relating to oil and gas producing activities	$ 24,199	$ 22,235	$ 20,655
Aggregate accumulated DD&A	(6,836)	(5,285)	(3,775)
Net capitalized costs	$ 17,363	$ 16,950	$ 16,880

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Year Ended December 31,		
(In millions)	2023	2022	2021[1]
Property acquisition costs, proved	$ —	$ —	$ 7,472
Property acquisition costs, unproved	10	10	5,386
Exploration costs	20	29	18
Development costs	1,979	1,617	688
Total costs	$ 2,009	$ 1,656	$ 13,564

(1) These amounts include the fair value of the proved and unproved properties recorded in the purchase price allocation with respect to the Merger. The purchase was funded through the issuance of the Company's common stock.

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

The following information has been developed based on oil and natural gas reserves and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and selling prices will differ from those required to be used in these calculations.
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.
- Selection of a 10 percent discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.
- Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by using the trailing 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year.

The average prices related to proved reserves are as follows:

	Year Ended December 31,		
	2023	2022	2021
Natural gas ($/Mcf)	$ 2.04	$ 5.25	$ 2.93
Oil ($/Bbl)	$ 75.05	$ 94.21	$ 65.40
NGLs ($/Bbl)	$ 18.39	$ 31.45	$ 25.74

Future cash inflows were reduced by estimated future development and production costs based on year end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations. The applicable accounting standards require the use of a 10 percent discount rate.

Management does not solely use the following information when making investment and operating decisions. These decisions are based on a number of factors, including estimates of proved reserves and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

Standardized Measure is as follows:

(In millions)	December 31, 2023	2022	2021
Future cash inflows	$ 45,749	$ 90,509	$ 60,908
Future production costs	(18,414)	(20,105)	(18,241)
Future development costs[(1)]	(3,239)	(3,859)	(2,449)
Future income tax expenses	(4,551)	(14,570)	(8,535)
Future net cash flows	19,545	51,975	31,683
10% annual discount for estimated timing of cash flows	(8,879)	(25,903)	(18,399)
Standardized measure of discounted future net cash flows	$ 10,666	$ 26,072	$ 13,284

(1) Includes $562 million, $544 million and $390 million in plugging and abandonment costs as of December 31, 2023, 2022 and 2021, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure:

(In millions)	Year Ended December 31, 2023	2022	2021
Beginning of year	$ 26,072	$ 13,284	$ 3,062
Discoveries and extensions, net of related future costs	1,578	5,944	800
Net changes in prices and production costs	(22,713)	17,462	9,573
Accretion of discount	3,348	1,919	551
Revisions of previous quantity estimates	(890)	(3,825)	467
Timing and other	979	55	(161)
Changes in estimated future development costs	220	65	(103)
Development costs incurred	1,232	604	497
Sales and transfers, net of production costs	(3,871)	(7,912)	(2,801)
Sales of reserves in place	(40)	(18)	(1)
Purchases of reserves in place	—	—	6,477
Net change in income taxes	4,751	(1,506)	(5,077)
End of year	$ 10,666	$ 26,072	$ 13,284

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2023, the Company carried out an evaluation, under the supervision and with the participation of the Company’s management, including the Company’s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company’s disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Exchange Act. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures are effective to provide reasonable assurance with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC’s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the fourth quarter of 2023 that have materially affected, or are reasonably likely to have a material effect on, the Company’s internal control over financial reporting.

Management’s Report on Internal Control over Financial Reporting

The management of Coterra Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Coterra Energy Inc.’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. 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.

Coterra Energy Inc.’s management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2023. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) in Internal Control—Integrated Framework (2013). Based on this assessment management has concluded that, as of December 31, 2023, the Company’s internal control over financial reporting is effective at a reasonable assurance level based on those criteria.

The effectiveness of Coterra Energy Inc.’s internal control over financial reporting as of December 31, 2023, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2023, no director or officer of Coterra adopted or terminated a “Rule 10b5-1 trading arrangement” or “no-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408 of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information set forth in Part 1 under the caption “Information about our Executive Officers” regarding our executive officers and the information set forth under the caption “Business—Other Business Matters—Corporate Governance Matters” in Item 1 regarding our Code of Business Conduct and Ethics is incorporated by reference in response to this item. The information required by this item is incorporated by reference from the Company’s definitive Proxy Statement in connection with the 2024 annual stockholders’ meeting.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from the Company’s definitive Proxy Statement in connection with the 2024 annual stockholders’ meeting.

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

The information required by this item is incorporated by reference from the Company’s definitive Proxy Statement in connection with the 2024 annual stockholders’ meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from the Company’s definitive Proxy Statement in connection with the 2024 annual stockholders’ meeting.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item is incorporated by reference from the Company’s definitive Proxy Statement in connection with the 2024 annual stockholders’ meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 52.

2. Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

3. Exhibits

The following instruments are included as exhibits to this report. Those exhibits below incorporated herein by reference are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, copies of the instrument have been included herewith. The Company’s file number with the SEC is 1-10447.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of May 23, 2021, by and among Cabot Oil & Gas Corporation, Double C Merger Sub, Inc. and Cimarex Energy Co. (incorporated herein by reference to Exhibit 2.1 of Coterra's Current Report on Form 8-K filed with the SEC on May 24, 2021).
2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of June 29, 2021, by and among Cabot Oil & Gas Corporation, Double C Merger Sub, Inc. and Cimarex Energy Co. (incorporated herein by reference to Annex A to the Joint Proxy Statement/Prospectus included in Coterra's Registration Statement on Form S-4 (Reg. No. 333-257534) filed with the SEC on June 30, 2021).
3.1	Restated Certificate of Incorporation of Coterra Energy Inc. (incorporated herein by reference to Exhibit 3.3 of Coterra's Current Report on Form 8-K filed with the SEC on October 1, 2021).
3.2	Amended and Restated Bylaws of Coterra Energy Inc. (incorporated herein by reference to Exhibit 3.2 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2023).
4.1	Description of Securities Registered Pursuant to Section 12 of Securities Exchange Act or 1934 (incorporated herein by reference to Exhibit 4.1 of Coterra's Annual Report on Form 10-K filed with the SEC on March 1, 2022.)
4.2	Form of Common Stock Certificate of Coterra Energy Inc. (incorporated herein by reference to Exhibit 4.3 of Coterra's Registration Statement on Form S-8 (Reg. No. 333-260035) filed with the SEC on October 5, 2021).
4.3	Certificate of Designations to 8 1⁄8% Series A Cumulative Perpetual Convertible Preferred Stock of Cimarex Energy Co. (incorporated herein by reference to Exhibit 4.3 of Coterra's Annual Report on Form 10-K filed with the SEC on March 1, 2022).
4.4	Amendment to Certificate of Designations to 8 1⁄8% Series A Cumulative Perpetual Convertible Preferred Stock of Cimarex Energy Co. (incorporated herein by reference to Exhibit 4.4 of Coterra's Annual Report on Form 10-K filed with the SEC on March 1, 2022).
4.5	Amendment to Certificate of Designations to 8 1/8% Series A Cumulative Perpetual Convertible Preferred Stock of Cimarex Energy Co. (incorporated herein by reference to Exhibit 4.3 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2022).
4.6	Note Purchase Agreement, dated as of September 18, 2014, among Cabot Oil & Gas Corporation and the Purchasers named therein (incorporated herein by reference to Exhibit 4.1 of Coterra's Current Report on Form 8-K filed with the SEC on September 24, 2014).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of December 31, 2015 (incorporated herein by reference to Exhibit 4.5 of Coterra's Current Report on Form 8-K filed with the SEC on February 9, 2016).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of April 8, 2016 (incorporated herein by reference to Exhibit 4.4(b) of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2016).
4.7	Indenture, dated as of October 7, 2021, by and between Coterra Energy Inc. and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 of Coterra's Current Report on Form 8-K filed

Table of Contents

4.9 Form of 3.90% Senior Notes due 2027 (incorporated herein by reference to Exhibit A-2 to the First Supplemental Indenture filed as Exhibit 4.2 of Coterra's Current Report on Form 8-K filed with the SEC on October 7, 2021).

4.10 Form of 4.375% Senior Notes due 2029 (incorporated herein by reference to Exhibit A-3 to the First Supplemental Indenture filed as Exhibit 4.2 of Coterra's Current Report on Form 8-K filed with the SEC on October 7, 2021).

Coterra or certain of its consolidated subsidiaries are parties to other debt instruments under which the total amount of securities authorized does not exceed 10 percent of Coterra's total consolidated assets. Pursuant to paragraph (4)(iii)(A) of Item 601(b) of Regulation S-K, Coterra agrees to furnish a copy of any of those instruments to the SEC upon its request.

*10.1 Form of Change in Control Agreement between Cabot Oil & Gas Corporation and Certain Officers (incorporated herein by reference to Exhibit 10.1 of Coterra's Annual Report on Form 10-K for the fiscal year ended December 31, 2008).

(a) Form of Change in Control Agreement between Cabot Oil & Gas Corporation and Certain Officers (Confirmation that Certain Benefits no Longer Apply) (incorporated herein by reference to Exhibit 10.1(a) of Coterra's Annual Report on Form 10-K for the fiscal year ended December 31, 2010).

(b) Form of Amendment to Change in Control Agreement (incorporated herein by reference to Exhibit 10.4 of Coterra's Registration Statement on Form S-4 (Reg. No. 333-257534) filed with the SEC on June 30, 2021).

(c) Form of Letter Agreement with respect to Change-in-Control Arrangements (incorporated herein by reference to Exhibit 10.1 of Coterra's Current Report on Form 8-K filed with the SEC on October 1, 2021).

(d) Amendment to Change in Control Agreement and Employment Letter Agreement dated December 27, 2022 (incorporated herein by reference to Exhibit 10.1 of Coterra's Current Report on Form 8-K filed with the SEC on December 29, 2022).

*10.2 Form of Indemnification Agreement between Cabot Oil & Gas Corporation and Certain Officers (incorporated herein by reference to Exhibit 10.2 of Coterra's Annual Report on Form 10-K for the fiscal year ended December 31, 2012).

*10.3 Form of Indemnification Agreement (incorporated herein by reference to Exhibit 10.3 of Coterra's Current Report on Form 8-K filed with the SEC on October 1, 2021).

*10.4 Deferred Compensation Plan of Cabot Oil & Gas Corporation, as Amended and Restated, Effective January 1, 2011 (incorporated herein by reference to Exhibit 10.1 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2011).

*10.5 Employment Letter Agreement, dated as of May 23, 2021, between Cabot Oil & Gas Corporation and Thomas E. Jorden (incorporated herein by reference to Exhibit 10.2 of Coterra's Registration Statement on Form S-4 (Reg. No. 333-257534) filed with the SEC on June 30, 2021).

*10.6 Side Letter Agreement, dated as of June 29, 2021, by and between Cabot Oil and Gas Corporation and Thomas E. Jorden (incorporated herein by reference to Exhibit 10.3 of Coterra's Registration Statement on Form S-4 (Reg. No. 333-257534) filed with the SEC on June 30, 2021).

*10.7 Amended and Restated Employment Letter Agreement dated as of

Table of Contents

(i) Form of Performance Share Unit Award Agreement (continuing officers) (incorporated herein by reference to Exhibit 10.1(b) of Coterra's Quarterly Report of Form 10-Q for the fiscal quarter ended March 31, 2023).

(j) Form of Performance Share Award Agreement (transitioning officers) (incorporated herein by reference to Exhibit 10.1(c) of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2023).

*10.10	Cimarex Energy Co. Amended and Restated 2019 Equity Incentive Plan, Effective May 12, 2021 (incorporated herein by reference to Exhibit 4.4 of Coterra's Registration Statement on Form S-8 (Reg. No. 333-260230) filed with the SEC on October 14, 2021).
	(a) Form of Restricted Stock Unit Award Agreement (legacy Cimarex continuing officers) (incorporated herein by reference to Exhibit 10.2 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2022);
	(b) Form of Restricted Stock Unit Award Agreement (legacy Cimarex transitioning officers) (incorporated herein by reference to Exhibit 10.2 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2022);
	(c) Form of Performance Share Award Agreement (legacy Cimarex continuing officers) (incorporated herein by reference to Exhibit 10.2 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2022);
	(d) Form of Performance Share Award Agreement (incorporated herein by reference to Exhibit 10.2 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2022).
*10.11	Coterra Energy Inc. 2023 Equity Incentive Plan (incorporated herein by reference to Exhibit 10.1 of Coterra's Current Report on Form 8-K filed with the SEC on May 4, 2023).
	(a) Form of Non-Employee Director Restricted Stock Unit Award Agreement (incorporated herein by reference to Exhibit 10.2(a) of Coterra's Current Report on Form 8-K filed with the SEC on May 4, 2023);
	(b) Form of Restricted Stock Unit Award Agreement (incorporated herein by reference to Exhibit 10.2(b) of Coterra's Current Report on Form 8-K filed with the SEC on May 4, 2023);
	(c) Form of Performance Stock Unit Award Agreement (incorporated herein by reference to Exhibit 10.2(c) of Coterra's Current Report on Form 8-K filed with the SEC on May 4, 2023);
	(d) Form of Restricted Stock Unit Award Agreement.
	(e) Form of Performance Stock Unit Award Agreement.
*10.12	Form of Severance Compensation Agreement of certain executive officers of Cimarex Energy Co. (incorporated herein by reference to Exhibit 10.1 of Cimarex's Current Report on Form 8-K filed with the SEC on March 13, 2020).
	(a) Form of Amendment to Severance Compensation Agreements of certain executive officers of Cimarex Energy Co. (incorporated herein by reference to Exhibit 10.11 of Coterra's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2021).
*10.13	Form of Executive Severance Compensation Agreement between Coterra Energy Inc. and certain officers (incorporated herein by reference to Exhibit 10.4 of Coterra's Current Report on Form 10-Q for

Table of Contents

99.1	DeGolyer and MacNaughton Report.
101.INS	Inline XBRL Instance Document. The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

---

* Compensatory plan, contract or arrangement.

ITEM 16. FORM 10-K SUMMARY

Coterra has elected not to include summary information.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 and 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, in the City of Houston, State of Texas, on February 23, 2024.

COTERRA ENERGY INC.

By: /s/ THOMAS E. JORDEN

Thomas E. Jorden
Chairman, Chief Executive Officer and President

Table of Contents

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 capacities and on the dates indicated.

Signature	Title	Date
/s/ THOMAS E. JORDEN Thomas E. Jorden	Chairman, Chief Executive Officer and President (Principal Executive Officer)	February 23, 2024
/s/ SHANNON E. YOUNG III Shannon E. Young III	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2024
/s/ TODD M. ROEMER Todd M. Roemer	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2024
/s/ DOROTHY M. ABLES Dorothy M. Ables	Director	February 23, 2024
/s/ ROBERT S. BOSWELL Robert S. Boswell	Lead Director	February 23, 2024
/s/ AMANDA M. BROCK Amanda M. Brock	Director	February 23, 2024
/s/ DAN O. DINGES Dan O. Dinges	Director	February 23, 2024
/s/ PAUL N. ECKLEY Paul N. Eckley	Director	February 23, 2024
/s/ HANS HELMERICH Hans Helmerich	Director	February 23, 2024
/s/ LISA A. STEWART Lisa A. Stewart	Director	February 23, 2024
/s/ FRANCES M. VALLEJO Frances M. Vallejo	Director	February 23, 2024