

**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

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM _____ TO _____
COMMISSION FILE NUMBER 001-03551

EQT CORPORATION

(Exact name of registrant as specified in its charter)

Pennsylvania

(State or other jurisdiction of incorporation or organization)

25-0464690

(IRS Employer Identification No.)

625 Liberty Avenue, Suite 1700

Pittsburgh, Pennsylvania
(Address of principal executive offices)

15222
(Zip Code)

(412) 553-5700

(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, no par value	EQT	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	<input checked="" type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

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 Exchange Act). Yes No
The aggregate market value of common stock, no par value, held by non-affiliates of the registrant as of June 30, 2023: \$14.7 billion

The number of shares of common stock, no par value, of the registrant outstanding (in thousands) as of February 9, 2024: 440,427

DOCUMENTS INCORPORATED BY REFERENCE

EQT Corporation's definitive proxy statement relating to its 2024 annual meeting of shareholders will be filed with the Securities and Exchange Commission within 120 days after the close of EQT Corporation's fiscal year ended December 31, 2023 and is incorporated by reference into Part III of this Annual Report on Form 10-K to the extent described therein.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Unless the context otherwise indicates, all references in this report to "EQT," the "Company," "we," "us," or "our" are to EQT Corporation and its subsidiaries, collectively.

Commonly Used Terms

Appalachian Basin – the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis – when referring to commodity pricing, the difference between the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing.

British thermal unit – a measure of the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit.

collar – a financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk and benefit of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

continuous accumulations – natural gas and oil resources that are pervasive throughout large areas, have ill-defined boundaries and typically lack, or are unaffected by, hydrocarbon-water contacts near the base of the accumulation.

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

exploratory well – a well drilled to find a new field or new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

extension well – a well drilled to extend the limits of a known reservoir.

gas – all references to "gas" in this report refer to natural gas.

gross – "gross" natural gas and oil wells or "gross" acres equal the total number of wells or acres in which we have a working interest.

hedging – the use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

horizontal drilling – drilling that ultimately is horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

horizontal wells – wells that are drilled horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

natural gas liquids (NGLs) – those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation or other methods in gas processing plants. Natural gas liquids include primarily ethane, propane, butane and isobutane.

net – "net" natural gas and oil wells or "net" acres equals the sum of our fractional ownership working interests we have in gross wells or acres.

net revenue interest – the interest retained by us in the revenues from a well or property after giving effect to all third-party interests (equal to 100% minus all royalties on a well or property).

option – a contract that gives the buyer the right, but not the obligation, to buy or sell a specified quantity of a commodity or other instrument at a specific price within a specified period of time.

play – a proven geological formation that contains commercial amounts of hydrocarbons.

productive well – a well that is producing oil or gas or that is capable of production.

proved reserves – quantities of natural gas, NGLs and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

proved developed reserves – proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves (PUDs) – proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.

reliable technology – a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

reservoir – a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

service well – a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include, among other things, gas injection, water injection and salt-water disposal.

stratigraphic test well – a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas.

turned-in-line – when a well is completed, producing and initially turned to sales.

well pad – an area of land that has been cleared and leveled to enable a drilling rig to operate in the exploration and development of a natural gas or oil well.

working interest – an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

Abbreviations

CFTC – Commodity Futures Trading Commission

EPA – U.S. Environmental Protection Agency

ESG – environmental, social and governance

FERC – Federal Energy Regulatory Commission

FTC – Federal Trade Commission

GAAP – U.S. Generally Accepted Accounting Principles

IRS – Internal Revenue Service

NYMEX – New York Mercantile Exchange

OTC – over the counter

SEC – U.S. Securities and Exchange Commission

WTI – West Texas Intermediate crude oil

Measurements

Bbl = barrel

Bcf = billion cubic feet

Bcfe = billion cubic feet of natural gas equivalents, with one barrel of NGLs and oil being equivalent to 6,000 cubic feet of natural gas

Btu = one British thermal unit

Dth = dekatherm or million British thermal units

Mbbl = thousand barrels

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of NGLs and oil being equivalent to 6,000 cubic feet of natural gas

MMbbl = million barrels

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas equivalents, with one barrel of NGLs and oil being equivalent to 6,000 cubic feet of natural gas

MMDth = million dekatherm

Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of NGLs and oil being equivalent to 6,000 cubic feet of natural gas

SUMMARY OF RISK FACTORS

We believe that the principal risks associated with our business, and consequently the principal risks associated with an investment in our equity or debt securities, generally fall within the following categories:

- **Risks Associated with Natural Gas Drilling, Transmission and Processing Operations.** As a natural gas producer, and an operator of certain transmission pipelines and processing facilities, there are risks inherent in our primary business operations. These risks are not necessarily unique to us, but rather, these are risks that most operators in our industry have at least some exposure to.
- **Financial and Market Risks.** Given that our primary product and source of revenue is the sale of natural gas and NGLs, one of our most material risks is the commodity market and the price of natural gas and NGLs, which is often volatile. Additionally, our operations are capital intensive. Pressures on the market as a whole, or our specific financial position – whether due to depressed commodity prices, our hedge positions, leverage, credit ratings, tax law changes or otherwise – could make it difficult for us to obtain the funding necessary to conduct our operations.
- **Risks Associated with Our Human Capital, Technology and Other Resources and Service Providers.** Our business, and the U.S. energy grid, is predominately operated on a digital system. Our employees rely on our cloud-based digital work environment to communicate and access data that is necessary to conduct our day-to-day operations. While these systems and infrastructure enable us to efficiently supply our natural gas, NGLs and oil to the market, they are also susceptible to physical and cybersecurity threats. Likewise, as a digitally-focused organization, we seek employees with a high degree of both technical skill and digital literacy, and it can be difficult to attract and retain personnel who satisfy these criteria. Further, we operate in the Appalachian Basin, and a substantial majority of our midstream and water services are provided by one provider, Equitrans Midstream Corporation (Equitrans Midstream), making us vulnerable to risks associated with operating primarily in one major geographic area and obtaining a substantial amount of our services from a single provider within that operating area.
- **Legal and Regulatory Risks.** There are many environmental, energy, financial, real property and other regulations that we are required to comply with in the context of conducting our operations; otherwise, we may be exposed to fines, penalties, investigations, litigation or other legal proceedings. Additionally, negative public perception of us or the natural gas industry, or increasing consumer demand for alternatives to natural gas, could adversely impact our earnings, cash flows and financial position.
- **Risks Associated with Strategic Transactions.** We have historically been involved in, and anticipate that we will continue to explore, opportunities to create value through strategic transactions, whether through mergers and acquisitions, divestitures, joint ventures or similar business transactions. There are risks inherent in any strategic transaction, and such risks could negatively affect the benefits, outcomes and synergies anticipated to be obtained from executing such strategic transactions.

We describe these risks in greater detail under Item 1A., "Risk Factors."

CAUTIONARY STATEMENTS

This Annual Report on Form 10-K contains certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and are usually identified by the use of words such as "anticipate," "estimate," "could," "would," "will," "may," "forecast," "approximate," "expect," "project," "intend," "plan," "believe" and other words of similar meaning, or the negative thereof. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report on Form 10-K include the matters discussed in sections "Strategy" and "Outlook" in Item 1., "Business," the section "Trends and Uncertainties" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations," and expectations of our plans, strategies, objectives and growth and anticipated financial and operational performance, including guidance regarding our strategy to develop our reserves; drilling plans and programs, including availability of capital to complete these plans and programs; total resource potential and drilling inventory duration; projected production and sales volume, including liquified natural gas (LNG) volumes and sales; natural gas prices; changes in basis and the impact of commodity prices on our business; potential future impairments of our assets; projected well costs and capital expenditures; infrastructure programs; the cost, capacity and timing of obtaining regulatory approvals; our ability to successfully implement and execute our operational, organizational, technological and ESG initiatives, and achieve the anticipated results of such initiatives; projected gathering and compression rates; potential acquisitions or other strategic transactions, the timing thereof and our ability to achieve the intended operational, financial and strategic benefits from any such transactions or from any recently completed strategic transactions; the amount and timing of any repayments, redemptions or repurchases of our common stock, outstanding debt securities or other debt instruments; our ability to retire our debt and the timing of such retirements, if any; the projected amount and timing of dividends; projected cash flows and free cash flow, and the timing thereof; liquidity and financing requirements, including funding sources and availability; our ability to maintain or improve our credit ratings, leverage levels and financial profile; our hedging strategy and projected margin posting obligations; the effects of litigation, government regulation and tax position; and the expected impact of changes to tax laws.

The forward-looking statements included in this Annual Report on Form 10-K involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. We have based these forward-looking statements on current expectations and assumptions about future events, taking into account all information currently known by us. While we consider these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, many of which are difficult to predict and beyond our control. These risks and uncertainties include, but are not limited to, those set forth in Item 1A., "Risk Factors" in this Annual Report on Form 10-K, and other documents we file from time to time with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, we do not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and our development program. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

In reviewing any agreements incorporated by reference in or filed with this Annual Report on Form 10-K, remember such agreements are included to provide information regarding the terms of such agreements and are not intended to provide any other factual or disclosure information about us. The agreements may contain representations and warranties by us, which should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to such agreements should those statements prove to be inaccurate. The representations and warranties were intended to be relied upon solely by the applicable party to such agreement and were made only as of the date of the relevant agreement or such other date or dates as may be specified in such agreement and are subject to more recent developments. Accordingly, such representations and warranties alone may not describe our actual state of affairs or the affairs of our affiliates as of the date they were made or at any other time and should not be relied upon as statements of fact.

PART I

Item 1. Business

General

We are a natural gas production company with operations focused in the Appalachian Basin. As of December 31, 2023, we had 27.6 Tcfe of proved natural gas, NGLs and oil reserves across approximately 2.1 million gross acres, and, based on average daily sales volume, we were the largest producer of natural gas in the United States.

Strategy

We are committed to responsibly developing our world-class asset base and being the operator of choice for all stakeholders. By promoting a culture that prioritizes operational efficiency, technology, sustainability and safety, we seek to continuously improve the way we produce environmentally responsible, reliable low-cost energy. We measure sustainability through consideration of our best-in-class team and culture, the ESG performance of our operations, our substantial inventory of core drilling locations and our investment grade balance sheet. We believe that the scale and contiguity of our acreage position differentiates us from our Appalachian Basin peers and that our digitally-enabled exploration and production business enhances our strategic advantage.

Our operational strategy focuses on the successful execution of combo-development projects. Combo-development refers to the development of several multi-well pads in tandem. Combo-development generates value across all levels of the reserves development process by maximizing operational and capital efficiencies. In the drilling stage, rigs spend more time drilling and less time transitioning to new sites. Advanced planning, a prerequisite to pursuing combo-development, facilitates the delivery of bulk hydraulic fracturing sand and piped fresh and recycled water (as opposed to truck-transported water), and provides the ability to continuously meet completions supply needs and the use of environmentally friendly technologies. Operational efficiencies realized from combo-development are passed on to our service providers, which reduces overall contract rates.

The benefits of combo-development extend beyond financial gains to include environmental and social interests. We have developed an integrated ESG program that interplays with our combo-development-driven operational strategy. Core tenets of our ESG program include investing in technology and human capital; improving data collection, analysis and reporting; and engaging with stakeholders to understand, and align our actions with, their needs and expectations. Combo-development, when compared to similar production from non-combo-development operations, translates into fewer trucks on the road, decreased fuel usage, shorter periods of noise pollution, fewer areas impacted by midstream pipeline construction and shortened duration of site operations, all of which fosters a greater focus on safety, environmental protection and social responsibility.

We believe that combo-development projects are key to delivering sustainably low well costs and higher returns on invested capital. Our business model has been developed to enable us to generate sustainable free cash flow and correspondingly, we have implemented a robust capital allocation strategy directed at responsibly developing our assets while also returning capital to our shareholders through a combination of debt retirements, dividends and strategic share repurchases. We are also focused on maintaining investment grade credit metrics, which allows us to capture a lower cost of capital and further enhance shareholder returns.

Our strategy, and combo-development projects in particular, requires significant advanced planning, including the establishment of a large, contiguous leasehold position; the advanced acquisition of regulatory permits and sourcing of fracturing sand and water; timely midstream connectivity; and the ability to quickly respond to internal and external stimuli. Without a digitally-connected operating model or an acreage position that enables operations of this scale, combo-development would not be possible. Furthermore, we believe the benefits of our operating model can be magnified through select strategic transactions, and part of our strategy includes creating value through mergers and acquisitions, divestitures, joint ventures and similar business transactions, as well as investing in energy transition opportunities directed at complementing, and in certain cases diversifying, our core business operations.

We believe that our proprietary digital work environment, in conjunction with the size and contiguity of our asset base, uniquely position us to execute on a multi-year inventory of combo-development projects in our core acreage position. Our operational strategy employs this differentiation to advance our mission of being the operator of choice for all stakeholders, while simultaneously helping to address energy security and affordability both domestically and globally.

2023 Highlights

- Generated \$3.2 billion of net cash provided by operating activities with an average NYMEX price of \$2.74 per MMBtu.
- Retired \$1.1 billion aggregate principal of debt.
- Increased quarterly base dividend by 5% to \$0.1575 per share (\$0.63 per share annualized).
- Paid \$228 million in dividends to shareholders.
- Repurchased \$200 million of common stock, reducing our outstanding share count by 5.9 million shares.
- Completed the Tug Hill and XcL Midstream Acquisition (defined and discussed in Note 6 to the Consolidated Financial Statements).
- Increased total proved reserves by 2,594 Bcfe, or 10.4%, compared to 2022.
- Achieved investment grade credit rating from Moody's Investors Services, making us investment grade rated by all three credit rating agencies.

Outlook

In 2024, we expect to spend approximately \$2.15 billion to \$2.35 billion in total capital expenditures. We expect to allocate the total planned capital expenditures as follows: approximately \$1,685 million to \$1,775 million to fund reserve development, approximately \$220 million to \$250 million to fund midstream and other infrastructure, approximately \$125 million to \$190 million to fund land and lease acquisitions, approximately \$70 million to \$80 million towards capitalized overhead and approximately \$50 million to \$55 million towards capitalized interest and other items. Included in total planned capital expenditures is approximately \$200 million to \$300 million for strategic growth projects composed of approximately \$70 million to \$90 million for water infrastructure within reserve development, approximately \$50 million to \$70 million for growth projects within midstream and other infrastructure and approximately \$80 million to \$140 million for in-fill leasing and mineral purchases within land and lease acquisitions. In 2024, we expect our sales volume to be 2,200 Bcfe to 2,300 Bcfe.

We are committed to maintaining investment grade credit metrics, and we have a goal to reduce our absolute debt to \$3.5 billion, subject to the overall performance of the commodity markets. Our capital allocation plan is focused on maintaining production volumes while also returning capital to shareholders, including through our quarterly cash dividend and share repurchase program, pursuant to which we are authorized to repurchase shares of our outstanding common stock for an aggregate purchase price of up to \$2 billion, excluding fees, commissions and expenses. Furthermore, we have aligned our hedge strategy in a manner that we believe will mitigate the risk of volatility of future natural gas and NGLs prices, thereby enabling us to execute on our capital expenditure, debt retirement and shareholder return strategy.

Our revenues, earnings and liquidity are substantially dependent on the prices we receive for, and our ability to develop our reserves of, natural gas, NGLs and oil. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, NGLs and oil at our ultimate sales points and, thus, cannot predict the ultimate impact of prices on our operations. Changes in natural gas, NGLs and oil prices could affect, among other things, our development plans, which would increase or decrease the pace of the development and the level of our reserves, as well as our revenues, earnings or liquidity. Lower prices and changes in our development plans could also result in non-cash impairments in the book value of our oil and gas properties or downward adjustments to our estimated proved reserves. Any such impairments or downward adjustments to our estimated reserves could potentially be material to us.

See "Critical Accounting Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our significant accounting policies and assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties. See also Item 1A., "Risk Factors – Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy may result in additional write-downs of the carrying amounts of our assets, including long-lived intangible assets, which could materially and adversely affect our results of operations in future periods."

Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis. Substantially all of our assets and operations are located in the Appalachian Basin.

Reserves

The following table summarizes our proved developed and undeveloped natural gas, NGLs and oil reserves using average first-day-of-the-month closing prices for the prior twelve months and disaggregated by product. Substantially all of our reserves reside in continuous accumulations.

	December 31, 2023		
	Natural Gas	NGLs and Oil	Total (a)
	(Bcf)	(MMbbl)	(Bcfe)
Proved developed reserves	18,186	229	19,558
Proved undeveloped reserves	7,609	72	8,039
Total proved reserves	25,795	301	27,597

- (a) The Marcellus Shale comprises 91% of our total proved developed reserves, 98% of our total proved undeveloped reserves and 93% of our total proved reserves.

The following table summarizes our proved developed and undeveloped reserves using average first-day-of-the-month closing prices for the prior twelve months and disaggregated by state.

	December 31, 2023			
	Pennsylvania	West Virginia	Ohio	Total
	(Bcfe)			
Proved developed producing reserves	12,855	5,312	552	18,719
Proved developed non-producing reserves	601	234	4	839
Proved undeveloped reserves	4,160	3,864	15	8,039
Total proved reserves	17,616	9,410	571	27,597
Gross proved undeveloped drilling locations	222	191	4	417
Net proved undeveloped drilling locations	174	172	1	347

Our 2023 total proved reserves increased by 2,594 Bcfe, or 10.4%, compared to 2022 due to extensions, discoveries and other additions of 3,412 Bcfe and acquisitions of 2,600 Bcfe from the Tug Hill and XcL Midstream Acquisition, partly offset by production of 2,016 Bcfe and revisions to previous estimates of 1,402 Bcfe.

Our 2023 proved undeveloped reserves increased by 550 Bcfe, or 7.3%, compared to 2022. The following table provides a roll-forward of our proved undeveloped reserves.

	Proved Undeveloped Reserves
	(Bcfe)
Balance at January 1, 2023	7,489
Conversions into proved developed reserves	(2,561)
Acquisition of in-place reserves	840
Revision of previous estimates (a)	(832)
Extensions, discoveries and other additions (b)	3,103
Balance at December 31, 2023	<u>8,039</u>

- (a) Composed of (i) negative revisions of 755 Bcfe related to proved undeveloped locations that we no longer expect to develop as proved reserves within five years of initial booking as a result of development schedule changes, (ii) negative revisions of 367 Bcfe due primarily to revisions to type curves and commodity price change, partly offset by (iii) positive revisions of 290 Bcfe due to changes in ownership interests.
- (b) Composed of (i) 1,670 Bcfe from proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2023 reserve development that expanded the number of our proven locations and additions to our five-year drilling plan, (ii) 1,341 Bcfe of proved undeveloped additions for previously proved undeveloped properties reclassified from unproved properties due to their addition to our five-year development plan and (iii) positive revisions of 92 Bcfe from the extension of lateral lengths of proved undeveloped reserves.

As of December 31, 2023, we had zero wells with proved undeveloped reserves that had remained undeveloped for more than five years from their time of booking.

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

	Years Ended December 31,		
	2023	2022	2021
	(Millions, unless otherwise noted)		
Future net cash flow	\$ 19,031	\$ 87,612	\$ 36,567
Standardized measure of discounted future net cash flow	9,262	40,065	17,281
PV-10 (a)	11,520	51,512	21,496
Prices, including regional adjustments:			
Natural gas price (\$/Mcf)	\$ 1.700	\$ 5.543	\$ 2.694
NGLs price (\$/Bbl)	28.44	38.66	29.95
Oil price (\$/Bbl)	63.86	76.83	51.57

- (a) PV-10 is a non-GAAP financial measure. PV-10 is derived from the standardized measure of discounted future net cash flows (the Standardized Measure), which is the most directly comparable financial measure computed using GAAP. PV-10 differs from the Standardized Measure because it does not include the effects of income taxes on future net revenues. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with GAAP. Neither PV-10 nor the Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. See below for a reconciliation of the Standardized Measure to PV-10.

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, operating expenses and production taxes) and net of estimated income taxes. Revenues are based on a twelve-month unweighted average of the first-day-of-the-month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information. See Note 14 to the Consolidated Financial Statements for further discussion of the preparation of, and year-over-year changes in, our reserves estimate and calculation of the standardized measure of estimated future net cash flows from natural gas and oil reserves.

The following table provides the reconciliation of the Standardized Measure to PV-10.

	Years Ended December 31,		
	2023	2022	2021
	(Millions)		
Standardized measure of discounted future net cash flow	\$ 9,262	\$ 40,065	\$ 17,281
Estimated discounted income taxes on future net revenues	2,258	11,447	4,215
PV-10	<u>\$ 11,520</u>	<u>\$ 51,512</u>	<u>\$ 21,496</u>

If the prices used in the calculation of the Standardized Measure instead reflected five-year strip pricing as of December 29, 2023 and held constant thereafter using (i) the NYMEX five-year strip adjusted for regional differentials using Texas Eastern Transmission Corp. M-2, Transcontinental Gas Pipe Line, Leidy Line, and Tennessee Gas Pipeline Co., Zone 4-300 Leg for gas and (ii) the NYMEX WTI five-year strip for oil, adjusted for regional differentials consistent with those used in the Standardized Measure, and holding all other assumptions constant, our total proved reserves would be 28,042 Bcfe, the Standardized Measure after taxes of our proved reserves would be \$18,176 million, the discounted future net cash flows before taxes would be \$22,903 million and the average realized product prices weighted by production over the remaining lives of the properties would be \$49.71 per barrel of oil, \$23.08 per barrel of NGLs and \$2.846 per Mcf of gas.

The NYMEX strip price for proved reserves and related metrics are intended to illustrate reserve sensitivities to market expectations of commodity prices and should not be confused with SEC pricing for proved reserves and do not comply with SEC pricing assumptions. We believe that the presentation of reserve volume and related metrics using NYMEX forward strip prices provides investors with additional useful information about our reserves because the forward prices are based on the market's forward-looking expectations of oil and gas prices as of a certain date. The price at which we can sell our production in the future is the major determinant of the likely economic producibility of our reserves. We hedge certain amounts of future production based on futures prices. In addition, we use such forward-looking market-based data in developing our drilling plans, assessing our capital expenditure needs and projecting future cash flows. While NYMEX strip prices represent a consensus estimate of future pricing, such prices are only an estimate and are not necessarily an accurate projection of future oil and gas prices. Actual future prices may vary significantly from NYMEX prices; therefore, actual revenue and value generated may be more or less than the amounts disclosed. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC pricing, when considering our reserves.

Based on our mix of proved undeveloped probable and possible reserves, we estimate that we have an undeveloped drilling inventory of approximately 4,000 gross locations. At our current drilling pace, these locations provide more than 30 years of drilling inventory based on gross undeveloped acres, average expected lateral length of 12,000 feet and well spacing of 1,000 feet. We believe that our combo-development strategy, coupled with our undeveloped inventory located in a premier core asset base, will lead to sustainable free cash flow generation and higher returns on invested capital.

For the years ended December 31, 2023, 2022 and 2021, lease operating expenses per Mcfe were \$0.08, \$0.08 and \$0.07, respectively.

Properties

The majority of our acreage is held by lease or occupied under perpetual easements or other rights acquired, for the most part, without warranty of underlying land titles. Approximately 36% of our total gross acres is developed. We retain deep drilling rights on the majority of our acreage.

The following table summarizes our acreage disaggregated by state.

	December 31, 2023			
	Pennsylvania	West Virginia	Ohio	Total
Total gross productive acreage	499,183	218,837	53,164	771,184
Total gross undeveloped acreage	854,790	405,166	112,774	1,372,730
Total gross acreage	1,353,973	624,003	165,938	2,143,914
Total net productive acreage	441,971	216,255	44,798	703,024
Total net undeveloped acreage	789,925	396,179	102,146	1,288,250
Total net acreage	1,231,896	612,434	146,944	1,991,274
Average net revenue interest of proved developed reserves (a)	60.1 %	79.4 %	41.2 %	63.6 %

(a) As of December 31, 2023, the average net revenue interest of proved developed reserves was 80.3% for southwestern Pennsylvania and 31.2% for northeastern Pennsylvania.

We have an active lease renewal program in areas targeted for development. In the event that production is not established or we do not extend or renew the terms of our expiring leases, 35,844, 22,097 and 30,206 of our net undeveloped acreage as of December 31, 2023 will expire in the years ending December 31, 2024, 2025 and 2026, respectively.

The following table summarizes our natural gas, NGLs and oil produced and sold volume by state.

	Pennsylvania	West Virginia	Ohio	Total
	(MMcfe)			
Year Ended December 31, 2023	1,496,197	435,898	84,178	2,016,273
Year Ended December 31, 2022	1,493,568	323,113	123,362	1,940,043
Year Ended December 31, 2021	1,422,294	271,747	163,776	1,857,817

Productive Wells

The following table summarizes our productive and in-process natural gas wells. We had no productive or in-process oil wells as of December 31, 2023.

	December 31, 2023			
	Pennsylvania	West Virginia	Ohio	Total
Productive wells:				
Total gross productive wells (a)	3,810	1,091	298	5,199
Total net productive wells	2,845	1,032	143	4,020
In-process wells:				
Total gross in-process wells	165	149	10	324
Total net in-process wells	126	140	3	269

(a) Of our total gross productive wells, there are 605 gross conventional wells in Pennsylvania and 16 gross conventional wells in West Virginia. We have no gross conventional wells in Ohio.

Drilling Activity

The following table summarizes our completed net productive development wells. During the years ended December 31, 2023, 2022 and 2021, we did not drill any net dry development, net productive exploratory or net dry exploratory wells.

	Pennsylvania	West Virginia	Ohio	Total
Year Ended December 31, 2023	91	47	2	140
Year Ended December 31, 2022	55	26	2	83
Year Ended December 31, 2021	60	17	5	82

The following table summarizes the gross and net wells on which we commenced drilling operations (spud) in 2023.

	Pennsylvania	West Virginia	Ohio	Total
Gross wells spud	99	30	19	148
Net wells spud	46	20	3	69

Markets and Customers

Natural Gas Sales. Natural gas is a commodity and, therefore, we typically receive market-based pricing for our produced natural gas. The market price for natural gas in the Appalachian Basin is typically lower relative to NYMEX Henry Hub, Louisiana (the location for pricing NYMEX natural gas futures) as a result of increased supply of natural gas in the Northeast United States and limited pipeline capacity to transport the supply to other regions. To protect our cash flow from undue exposure to the risk of changing commodity prices, we hedge a portion of our forecasted natural gas production at, for the most part, NYMEX natural gas prices. We also enter into derivative instruments to hedge basis. For information on our hedging strategy and our derivative instruments, refer to "Commodity Risk Management" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations," Item 7A., "Quantitative and Qualitative Disclosures About Market Risk" and Note 3 to the Consolidated Financial Statements.

NGLs Sales. We primarily sell NGLs recovered from our natural gas production. We contract with MarkWest Energy Partners, L.P., Williams Ohio Valley Midstream LLC and Blue Racer Midstream to process our natural gas and extract heavier hydrocarbon streams (consisting predominately of ethane, propane, isobutane, normal butane and natural gasoline) from our produced natural gas. We market the majority of our NGLs.

Average Sales Price. The following table presents our average sales price per unit of natural gas, NGLs and oil, with and without the effects of cash settled derivatives, as applicable.

	Years Ended December 31,		
	2023	2022	2021
Natural gas (\$/Mcf):			
Average sales price, excluding cash settled derivatives	\$ 2.37	\$ 6.22	\$ 3.54
Average sales price, including cash settled derivatives	2.68	3.00	2.38
NGLs, excluding ethane (\$/Bbl):			
Average sales price, excluding cash settled derivatives	\$ 36.39	\$ 53.26	\$ 44.50
Average sales price, including cash settled derivatives	35.12	49.35	32.18
Ethane (\$/Bbl):			
Average sales price	\$ 6.00	\$ 14.20	\$ 8.85
Oil (\$/Bbl):			
Average sales price	\$ 59.93	\$ 77.06	\$ 56.82
Natural gas, NGLs and oil (\$/Mcfe):			
Average sales price, excluding cash settled derivatives	\$ 2.50	\$ 6.24	\$ 3.66
Average sales price, including cash settled derivatives	2.79	3.17	2.50

For additional information on pricing, see "Average Realized Price Reconciliation" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Natural Gas Marketing. EQT Energy, LLC, our indirect, wholly-owned marketing subsidiary, provides marketing services and contractual pipeline capacity management services primarily for our benefit. EQT Energy, LLC also engages in risk management and hedging activities to limit our exposure to shifts in market prices.

Customers. We sell natural gas and NGLs to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through our transportation portfolio, particularly where there is expected future demand growth, such as in the Gulf Coast, Midwest and Northeast United States and Canada. As of December 31, 2023, approximately 42% of our sales volume reaches markets outside of Appalachia. We do not depend on any single customer and believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil.

We have access to approximately 3.6 Bcf per day of firm pipeline takeaway capacity and 0.9 Bcf per day of firm processing capacity. In addition, we are committed to an initial 1.29 Bcf per day of firm capacity on the Mountain Valley Pipeline once in service. These firm transportation and processing agreements may require minimum volume delivery commitments, which we expect to principally fulfill with production from existing reserves.

We have contractually agreed to deliver firm quantities of gas and NGLs to various customers, which we expect to fulfill with production from existing reserves. We regularly monitor our proved developed reserves to ensure sufficient availability to meet commitments for the next one to three years. The following table summarizes our total gross commitments as of December 31, 2023.

	Natural Gas	NGLs
	(Bcf)	(Mbbbl)
Years Ending December 31,		
2024	1,348	9,150
2025	447	5,475
2026	371	4,250
2027	337	3,650
2028	315	3,660
Thereafter	1,840	31,030

During the fourth quarter of 2023, we entered into two firm sales agreements, pursuant to which we agreed to deliver and sell to the parties thereto up to an aggregate 1.2 Bcf per day of gas using our Mountain Valley Pipeline capacity for up to ten years beginning in 2027. The firm sales agreements are subject to currently unsatisfied conditions related to the in-service dates of the Mountain Valley Pipeline and Transco Southeast Supply Enhancement; therefore, their impact has been excluded from the schedule of total gross commitments in the table above.

Seasonality

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or summers may also affect demand.

Competition

Other natural gas producers compete with us in the acquisition of properties; the search for, and development of, reserves; the production and sale of natural gas and NGLs; and the securing of services, labor, equipment and transportation required to conduct operations. Our competitors include independent oil and gas companies, major oil and gas companies, individual producers, operators and marketing companies and other energy companies that produce substitutes for the commodities that we produce.

Regulation

Regulation of our Operations. Our exploration and production operations are subject to various federal, state and local laws and regulations, including regulations related to the following: the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations, and any delays in obtaining related authorizations, may affect the costs and timing of developing our natural gas resources.

Our operations are also subject to conservation and correlative rights regulations, including the following: regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of natural gas properties. Ohio allows the statutory pooling or unitization of tracts to facilitate development and exploration. In Pennsylvania, lease integration legislation authorizes joint development of existing contiguous leases. West Virginia allows the operator of a proposed horizontal well to develop the acreage of non-consenting and unlocatable and unknown owners if 75% of the mineral interest owners and 55% of the working interest owners in the proposed well unit consent to the development. Additionally, state conservation and oil and gas laws generally limit the venting or flaring of natural gas. Various states also impose certain regulatory requirements to transfer wells to third parties or discontinue operations in the event of divestitures by us.

We also have gathering and processing operations used for our own produced natural gas and NGLs that are subject to various federal and state environmental laws and local zoning ordinances, including the following: air permitting requirements for compressor station and dehydration units and other permitting requirements; erosion and sediment control requirements for compressor station and pipeline construction projects; waste management requirements and spill prevention plans for compressor stations; various recordkeeping and reporting requirements for air permits and waste management practices; compliance with safety regulations, including regulations by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration; and siting and noise regulations for compressor stations. These regulations may increase the costs of operating existing pipelines and compressor stations and increase the costs of, and the time to develop, new or expanded pipelines and compressor stations.

We use financial derivative instruments to hedge the impact of fluctuations in natural gas, NGLs and oil prices on our results of operations and cash flows. In 2010, Congress adopted comprehensive financial reform legislation that established federal oversight and regulation of the OTC derivative market and entities, such as us, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing this legislation. Among other things, the Dodd-Frank Act established margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail or alter their derivative activities. The Dodd-Frank Act also created new categories of regulated market participants, such as "swap dealers" (SDs) and "security-based swap dealers" (SBSDs) that are subject to significant new capital, registration, recordkeeping, reporting, disclosure, business conduct and other regulatory requirements, a large number of which have been implemented. This regulatory framework has significantly increased the costs of entering into derivatives transactions for end-users of derivatives, such as ourselves. In particular, new margin requirements and capital charges, even when not directly applicable to us, have increased the pricing of derivatives that we transact in.

New exchange trading margin regulations, trade reporting requirements and position limits may lead to changes in the liquidity of our derivative transactions or higher pricing. That said, our hedging activities are not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing, although we are subject to certain recordkeeping and reporting obligations associated with the Dodd-Frank Act. Additionally, our uncleared swaps are not subject to regulatory margin requirements. Finally, we believe that the majority, if not all, of our hedging activities constitute bona fide hedging under applicable federal and exchange-mandated position limits rules and are not materially impacted by the limitations under such rules.

In addition to U.S. laws and regulations relating to derivatives, certain non-U.S. regulatory authorities have passed or proposed, or may propose in the future, legislation similar to that imposed by the Dodd-Frank Act. For example, European Union legislation imposes position limits on certain commodity transactions, and the European Market Infrastructure Regulation (EMIR) requires reporting of derivatives and various risk mitigation techniques to be applied to derivatives entered into by parties that are subject to EMIR. Other similar regulations are in development throughout the globe and may increase our cost of doing business even if not directly binding on us.

Regulators periodically review or audit our compliance with applicable regulatory requirements. We anticipate that compliance with existing laws and regulations governing our current operations will not have a material adverse effect on our capital expenditures, earnings or competitive position. Additional proposals that affect the oil and gas industry are regularly considered by Congress, the states, regulatory agencies and the courts. We cannot predict when or whether any such proposals may become effective or the effect that such proposals may have on us.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Natural Gas Sales and Transportation. The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC's regulations for interstate oil and natural gas transportation in some circumstances may also affect the intrastate transportation of oil and natural gas.

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties of over \$1.5 million per day for each violation and disgorgement of profits associated with any violation. While our production activities have not been regulated by the FERC as a natural gas company under the NGA, we are required to report the aggregate volume of natural gas purchased or sold at wholesale to the extent such transactions use, contribute to or may contribute to the formation of price indices. In addition, Congress may enact legislation or the FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalties.

The CFTC also holds authority to monitor certain segments of the physical, futures and other derivatives energy commodities markets, including natural gas, NGLs and oil. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation and disruptive trading practices laws and related regulations enforced by the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide non-unduly discriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. The FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas-related activities.

Under the FERC's current regulatory regime, transportation services must be provided on an open-access, nondiscriminatory basis at cost-based rates or negotiated rates, both of which are subject to FERC approval. The FERC also allows jurisdictional natural gas pipeline companies to charge market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of FERC-jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that the FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, and, depending on the scope of that decision, our costs of transporting natural gas to point of sale locations may increase. We believe that the third-party natural gas pipelines on which our gas is gathered meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between the FERC-regulated transportation services and federally unregulated gathering services could be subject to potential litigation, and the classification and regulation of those gathering facilities are subject to change based on future determinations by the FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Oil and NGLs Price Controls and Transportation Rates. Sales prices of oil and NGLs are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and regulations issued by the FTC prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of almost \$1.5 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight and enforcement authority as discussed above.

The price we receive from the sale of our produced oil and NGLs may be affected by the cost of transporting such products to market. Some of our transportation of oil and NGLs is through FERC-regulated interstate common carrier pipelines. Effective as of 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. The FERC's regulation of oil and NGLs transportation rates may tend to increase the cost of transporting oil and NGLs by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. 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. The FERC's five-year index level for 2021 through 2026 went into effect on July 1, 2021. In January 2022, the FERC issued an order on rehearing, lowering the index level and directing oil pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022 to ensure compliance with the new index level.

Environmental, Health and Safety Regulations. Our business operations are also subject to numerous stringent federal, state and local environmental, health and safety laws and regulations pertaining to, among other things, the release, emission or discharge of materials into the environment; the generation, storage, transportation, handling and disposal of certain materials, including solid and hazardous wastes; the safety of employees and the general public; pollution; site remediation; and preservation or protection of human health and safety, natural resources, wildlife and the environment. We must take into account environmental, health and safety regulations in, among other things, planning, designing, constructing, operating and plugging and abandoning wells and related facilities. Violations of these laws can result in substantial administrative, civil and criminal penalties. These laws and regulations may require us to acquire permits before drilling, constructing pipelines or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with our operations; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities or pipeline construction in certain areas and on certain lands lying within wilderness, wetlands and other protected areas or areas with endangered or threatened species restrictions; require some form of remedial action to prevent, remediate or mitigate pollution from operations, such as plugging abandoned wells or closing earthen pits; establish specific health and safety criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with applicable laws and regulations. In addition, these laws and regulations may restrict the rate of our production.

Moreover, the trend has been for stricter regulation of activities that have the potential to affect the environment. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, federal agencies, the states, local governments and the courts. We cannot predict when or whether any such proposals may become effective. Therefore, we are unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. We have established procedures, however, for the ongoing evaluation of our operations to identify potential environmental exposures and to track compliance with regulatory policies and procedures.

The following is a summary of the more significant environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our financial condition, earnings or cash flows.

Hazardous Substances and Waste Handling. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. 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 and for damages to natural resources, and 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 addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses oil and natural gas, we generate materials in the course of our operations that may be regulated as hazardous substances based on their characteristics; however, we are unaware of any liabilities arising under CERCLA for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act (RCRA) and analogous state laws establish detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced water and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, or under state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes currently classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. Any changes to state or federal programs could result in an increase in our costs to manage and dispose waste, which could have a material adverse effect on our results of operations and financial condition.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have used operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including offsite locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. We are able to directly control the operation of only those wells with respect to which we act or have acted as operator. The failure of a prior owner or operator to comply with applicable environmental regulations may, in certain circumstances, be attributed to us as the current owner or operator under CERCLA. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, regardless of fault, which could include removal of previously disposed substances and wastes, clean-up of contaminated property or performance of remedial plugging or waste pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, known as the Clean Water Act (CWA), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state equivalent agency. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (Corps). In June 2015, the EPA and the Corps issued a rule defining the scope of the EPA's and the Corps' jurisdiction over waters of the United States (WOTUS), which never took effect before being replaced by the Navigable Waters Protection Rule (NWPR) in December 2019. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. In January 2023, the EPA and the Corps issued a final rule that based the definition of WOTUS on the pre-2015 definition. The definition of WOTUS was further impacted by the U.S. Supreme Court's decision issued in May 2023 in *Sackett v. EPA*, wherein the Court held that the jurisdiction of the CWA extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection and rejected the "significant nexus" test embraced in earlier jurisprudence. In September 2023, the EPA and the Corps published a direct-to-final rule redefining WOTUS to amend the January 2023 rule and align with the decision in *Sackett*. The final rule eliminated the "significant nexus" test from consideration when determining federal jurisdiction and clarified that the CWA only extends to relatively permanent bodies of water and wetlands that have a continuous surface connection with such bodies of water. In addition, in an April 2020 decision further defining the scope of the CWA, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. To the extent a new rule or further litigation expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could delay our development projects and pipeline construction. Also, pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or stormwater and to develop and implement spill prevention, control and countermeasure (SPCC) plans in connection with on-site storage of significant quantities of oil. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal and remediation and other damages.

Air Emissions. Through the federal Clean Air Act (CAA) and comparable state and local laws and regulations, the EPA regulates emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits.

In November 2021, the EPA announced a proposed rule expanding upon its New Source Performance Standards (NSPS) rule, establishing standards for methane and volatile organic compounds (VOCs) from new and modified oil and natural gas production and natural gas processing and transmission facilities which would establish standards for existing wells, impose more frequent and stringent leak monitoring, and mandate that all pneumatic controllers have zero emissions. The proposed rule sought to make existing regulations more stringent, create a Subpart OOOOb to expand reduction requirements for new, modified and reconstructed natural gas and oil sources, and create a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. In November 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule, which, among other things, created a new third-party monitoring program to identify large emissions events, referred to in the proposed rule as "super emitters." The EPA announced a final rule in December 2023, which, among other things, requires the phase out of routine flaring of natural gas from new oil wells and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with applicable compliance dates under state plans. The final rule gives states two years to develop and submit their plans for reducing methane from existing sources. Subpart OOOOc then provides three years from the plan submission deadline for existing sources to comply.

As a result of these regulatory changes, the scope of any final air emissions regulations or the costs for complying with such regulations are uncertain. We may incur costs as necessary to remain in compliance with these regulations. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

Climate Change and Regulation of Methane and Other Greenhouse Gas Emissions. In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change (COP) resulted in nearly 200 countries, including the United States, coming together to develop the Paris Agreement, which calls for the signatories to the agreement to undertake "ambitious efforts" to limit increases in the average global temperature. Although the agreement does not create any binding obligations for nations to limit their greenhouse gas (GHG) emissions, it does require pledges to voluntarily limit or reduce future emissions. Pursuant to the terms of the Paris Agreement, the Biden Administration announced goals aimed at reducing the U.S.'s GHG emissions by 50 – 52% (compared to 2005 levels) by 2030. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030. Since its formal launch at COP26, over 150 countries have joined the Global Methane Pledge, and at COP27, the Biden Administration agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. In November 2023, the European Union reached a provisional political agreement on a regulation to track and reduce methane emissions in the energy sector. The regulation introduces new requirements for the oil and gas sectors to measure, report and verify methane emissions and implements mitigation measures to avoid such emissions. The regulation also introduces new global monitoring tools to ensure transparency on methane emissions from imports of oil, gas and coal into the European Union. Monitoring, reporting and verification measures will be required to be applied by exporters to the European Union by January 1, 2027 and "maximum methane intensity values" must be met by 2030. Each member state will have the power to impose administrative penalties for failure to comply and the standard will be mandatory for supply contracts signed after the law takes effect. Most recently, at COP28, President Biden announced the EPA's final standards to reduce methane emissions from existing oil and gas sources. Additionally, at COP28, nearly 200 countries, including the United States, agreed to transition away from fossil fuels while accelerating action in this decade to achieve net zero by 2050 and entered into an agreement that calls for actions towards achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts towards the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement.

In recent years, the U.S. Congress has considered legislation to reduce GHG emissions. While Congress has not passed comprehensive climate legislation regulating the emission of GHGs, energy legislation and other regulatory initiatives have been enacted or proposed that are relevant to GHG emissions and climate change. In particular, in November 2021, Congress approved a \$1 trillion legislative infrastructure package known as the Inflation Reduction Act of 2022 (IRA) which includes a number of climate-focused spending initiatives. The IRA also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change, including instituting a methane emissions reduction program known as the Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a fee known as a "waste emissions charge" on methane emissions from certain natural gas and oil facilities that are in excess of a specified threshold. In January 2024, the EPA proposed a rule implementing the IRA's methane emissions charge. The methane emissions charge imposed under the program for 2024 is \$900 per ton emitted over the annual methane emissions threshold, and will increase to \$1,200 in 2025, and \$1,500 in 2026. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the IRA. For petroleum and natural gas production facilities, the threshold is methane emissions in excess of 0.2% of the natural gas sent to sale from the facility. If a facility's methane emissions do not exceed the 0.2% threshold, no fee would be assessed under the program. Further, in July 2023, the EPA proposed to expand the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas systems (Subpart W), as required by the IRA. Among other things, the proposed rule expands the emissions events that are subject to reporting requirements to include "other large release events" and applies reporting requirements to certain new sources and sectors, which may result in an increase in reported methane and other GHG emissions under Subpart W for many operators, including us. The rule is currently scheduled to be finalized in the spring of 2024 and would take effect on January 1, 2025 in advance of the deadline for reporting emissions for calendar year 2024 under Subpart W.

Furthermore, in May 2023, the EPA issued proposed carbon emission limits and guidelines for new, modified, reconstructed and existing fossil fuel-fired (i.e., coal, oil and gas-fired) power plants. The proposed rule purports to reflect the best system of emissions reduction and use of technology-based improvements, including carbon capture and sequestration and low-GHG hydrogen. The proposed rule also revises the NSPS for new fossil fuel-fired stationary combustion turbine units and existing fossil fuel-fired steam generating electric generating units (EGUs), proposes new GHG emissions guidelines for existing fossil fuel-fired steam generating EGUs and for existing large, frequently operated stationary combustion turbines. The proposed rule requires states to submit plans for the establishment, implementation, and enforcement of performance standards for existing sources to the EPA within 24 months of the effective date of the emission guidelines, and compliance deadlines for stationary sources begin by 2030 for existing steam generating units, and 2032 or 2035 for existing combustion turbine units, depending on their subcategory. A supplemental notice of proposed rulemaking was issued in November 2023, which requested comments on the EPA's initial regulatory flexibility analysis of the rule (particularly reliability concerns raised by small businesses and other commenters), and a final rule is anticipated by April 2024.

Additionally, a number of U.S. state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of carbon taxes, policies and incentives, and cap-and-trade programs. In October 2019, then-Pennsylvania Governor Tom Wolf signed an Executive Order directing the Pennsylvania Department of Environmental Protection to draft regulations establishing a cap-and-trade program with the intent of enabling Pennsylvania to join the Regional Greenhouse Gas Initiative (RGGI), a multi-state regional cap-and-trade program comprised of several Eastern U.S. states. Pennsylvania became a member of RGGI in April 2022; however, since joining RGGI, Pennsylvania's membership has been the subject of various legal challenges. Most recently, in November 2023, the Pennsylvania Commonwealth Court held that the state's participation in RGGI is unconstitutional, and funds raised by the state through its participation in RGGI constitute an invalid tax, which ruling has been appealed. At this time, it is unclear to what extent, if any, Pennsylvania will continue to seek participation in RGGI or a similar emissions cap-and-trade program.

Regulations requiring the disclosure of GHG emissions and other climate-related information or information substantiating climate-related claims are also increasingly being adopted or proposed at the federal and state level. For example, the SEC issued a proposed rule in March 2022 that would mandate extensive disclosure of climate-related data, risks, and opportunities, including financial impacts, physical and transition risks, related governance and strategy, and GHG emissions, for certain public companies. At the state level, California enacted legislation in October 2023 that will ultimately require certain companies that do business in California to publicly disclose their Scopes 1, 2, and 3 GHG emissions, with third party assurance of such data, and issue public reports on their climate-related financial risk and related mitigation measures, as well as legislation that requires companies operating in California to disclose information that supports certain climate-related claims.

Any legislation or regulatory programs at the international, federal, state or city levels designed to reduce methane or other GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas, NGLs and oil we produce. Consequently, legislation and regulatory programs designed to reduce emissions of methane or other GHGs could have an adverse effect on our business, financial condition and results of operations.

It is not possible at this time to predict how legislation or regulations that may be adopted to address climate change, methane and other GHG emissions would impact our business. However, existing laws and regulations and any such future laws and regulations of this nature, including those imposing reporting obligations on, or imposing a tax or fee or otherwise limiting emissions of methane or other GHG emissions from, our equipment and operations could require us to incur costs to comply with such regulations. Substantial limitations or fees on methane or other GHG emissions could also adversely affect demand for the natural gas, NGLs and oil we produce and lower the value of our reserves.

Further, recent activism directed at shifting funding away from fossil fuel companies could result in limitations or restrictions on certain sources of funding for the sector. Moreover, activist shareholders have introduced proposals to certain companies seeking to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere produce climate changes that may have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events. If any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our operations.

Hydraulic Fracturing Activities. Vast quantities of natural gas deposits exist in shale and other formations. It is customary in our industry to recover natural gas from these shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deeper formations are geologically separated and isolated from fresh ground water supplies by overlying rock layers. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers. To assess water sources near our drilling locations, we conduct multiple pre-drill samplings for all water sources within 3,000 feet of our sites and post-drill samplings for sources within 1,500 feet of our sites.

Hydraulic fracturing typically is regulated by state oil and natural gas agencies, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (SDWA) over certain hydraulic fracturing activities involving the use of diesel fuels and has prohibited the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from constructing wells.

Occupational Safety and Health Act. We are also subject to the requirements of the federal Occupational Safety and Health Act and comparable state laws that regulate the protection of the health and safety of employees. In addition, the Occupational Health and Safety Administration's (OSHA) hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require us to maintain information about hazardous materials used or produced in our operations and this information is required to be provided to employees, state and local government authorities, and citizens.

Endangered Species Act and Migratory Bird Treaty Act. The federal Endangered Species Act (ESA) provides for the protection of 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 (FWS) may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. In June and July 2022, the FWS issued final rules rescinding the regulations defining "habitat" and governing critical habitat exclusions. In June 2023, the FWS issued three proposed rules governing interagency cooperation, listing species and designating critical habitat, and expanding protection options for species listed as threatened pursuant to the ESA. The final rules are expected by April 2024. Protections similar to the ESA are offered to migratory birds under the Migratory Bird Treaty Act (MBTA), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. In January 2021, the Department of the Interior finalized a rule limiting application of the MBTA; however, the Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental taking under certain prescribed conditions. The proposed rule was anticipated in November 2023, with final action expected by April 2024, but the FWS instead announced in November 2023 that it had received additional technical comments that need further review. Future implementation of the rules impacting the ESA and the MBTA are uncertain. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for natural gas development. Further, the designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, production and midstream activities that could have an adverse impact on our ability to develop and produce reserves and transport products to points of sale. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures that may adversely impact our business or operations.

See Note 11 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Human Capital Resources

As of December 31, 2023, we had 881 employees (excluding temporary employees and contractors), none of whom were subject to a collective bargaining agreement. Of our employee base, 76% are male and 24% are female. Approximately 64% of our employees work remotely, with 94% residing in Pennsylvania, Texas or West Virginia.

We aim to develop a workforce that produces peer leading results. To further that goal, we have focused on creating a modern, innovative, collaborative and digitally-enabled work environment. Our cloud-based digital work environment serves as our primary platform for communication and collaboration as well as the home for our critical work processes and drives decision-making based on a shared and transparent view of operational data. We use our digital work environment to engage directly with our employees by sharing company updates and personnel accomplishments as well as to solicit suggestions and comments from all employees. We believe that this helps promote real-time feedback and a greater degree of employee engagement, which lays the foundation for the success of our workforce.

We understand that providing employees with the resources and support they need to live a physically, mentally and financially healthy life is critical for sustaining a workplace of choice. We offer benefits that include subsidized health insurance, a company contribution and company match on 401(k) retirement savings, an employee stock purchase plan, paid maternity and paternity leave, flexible work arrangements, volunteer time off and a company match on employee donations to qualified non-profits. We also offer our employees the flexibility to elect to work a "9/80" work schedule, under which, during the standard 80-hour pay period, an employee works eight 9-hour days and one 8-hour day (Friday), with a tenth day off (alternating Fridays).

We also offer an "equity-for-all" program, pursuant to which, we grant annual equity awards to all of our employees. With the equity-for-all program, all of our employees become owners of EQT and have the opportunity to share directly in our financial success.

Availability of Reports and Other Information

We make certain filings with the SEC, including our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through our investor relations website, <http://ir.eqt.com>, as soon as reasonably practicable after they are filed with or furnished to the SEC. Reports filed with the SEC are also available on the SEC's website, <http://www.sec.gov>.

We use our X (formerly known as Twitter) account, @EQTCorp, our Facebook account, @EQTCorporation, and our LinkedIn account, EQT Corporation, as additional ways of disseminating information that may be relevant to investors.

We generally post the following to our investor relations website shortly before or promptly following its first use or release: financially-related press releases, including earnings releases and supplemental financial information; various SEC filings; presentation materials associated with earnings and other investor conference calls or events; and access to live and recorded audio from earnings and other investor conference calls or events. In certain cases, we may post the presentation materials for other investor conference calls or events several days prior to the call or event. For earnings and other conference calls or events, we generally include within our posted materials a cautionary statement regarding forward-looking and non-GAAP financial information as well as non-GAAP to GAAP financial information reconciliations (if available). Such GAAP reconciliations may be in materials for the applicable presentation, in materials for prior presentations or in our annual, quarterly or current reports.

In certain circumstances, we may post information, such as presentation materials and press releases, to our corporate website, www.EQT.com, or our investor relations website to expedite public access to information regarding EQT in lieu of making a filing with the SEC for first disclosure of the information. When permissible, we expect to continue to do so without also providing disclosure of this information through filings with the SEC.

Where we have included internet addresses in this Annual Report on Form 10-K, we have included those internet addresses as inactive textual references only. Except as specifically incorporated by reference into this Annual Report on Form 10-K, information on those websites is not part hereof.

Composition of Operating Revenues

The following table presents total operating revenues for each class of our products and services.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	\$ 5,044,768	\$ 12,114,168	\$ 6,804,020
Gain (loss) on derivatives	1,838,941	(4,642,932)	(3,775,042)
Net marketing services and other	25,214	26,453	35,685
Total operating revenues	<u>\$ 6,908,923</u>	<u>\$ 7,497,689</u>	<u>\$ 3,064,663</u>

Jurisdiction and Year of Formation

We are a Pennsylvania corporation formed in 2008 in connection with a holding company reorganization of the former Equitable Resources, Inc.

Item 1A. Risk Factors

In addition to the other information contained in this Annual Report on Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. Note that additional risks not presently known to us or that are currently considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occur, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

Risks Associated with Natural Gas Drilling, Transmission and Processing Operations

Drilling for and producing natural gas is a high-risk and costly activity with many uncertainties. Our future financial position, cash flows and results of operations depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production or that we will not recover all or any portion of our investment in drilled wells.

Many factors may curtail, delay or cancel our scheduled drilling projects, or the development schedule of wells which we do not operate but in which we have a working interest (referred to as non-operated wells), including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations resulting from permitting, wastewater disposal, emission of GHGs, and limitations on hydraulic fracturing;
- shortages of or delays in obtaining equipment, rigs, materials, qualified personnel or water (for hydraulic fracturing activities);
- supply chain disruptions or labor shortage impacts;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering and water facilities or delays in the construction of gathering and water facilities;
- lack of available capacity on interconnecting transportation pipelines;
- adverse weather conditions, such as flooding, droughts, freeze-offs, landslides, blizzards and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil and diesel spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in natural gas, NGLs and oil market prices;
- limited availability of financing at acceptable terms;
- ongoing litigation or adverse court rulings;
- public opposition to our operations;
- title, surface access, coal mining and right of way issues; and
- limitations in the market for natural gas, NGLs and oil.

Any of these risks can cause a delay in our development program or the scheduled development of non-operated wells in which we have a working interest, or result in substantial financial losses, personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. Additionally, we cannot control or otherwise influence the development schedule of non-operated wells in which we have a working interest. Adjustments to our planned development schedule or the development schedule of non-operated wells in which we have a working interest could impact our future sales volume, operating revenues and expenses, per unit metrics and capital expenditures.

We are subject to risks associated with the operation of our wells, pipelines and facilities.

Our business is subject to all of the inherent hazards and risks normally incidental to drilling for, producing, transporting, storing, processing, gathering and compressing natural gas, NGLs and oil, such as fires, explosions, slips, landslides, blowouts, and well cratering; pipe and other equipment and system failures; delays imposed by, or resulting from, compliance with regulatory requirements; formations with abnormal or unexpected pressures; shortages of, or delays in, obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities; adverse weather conditions, such as freeze offs of wells and pipelines due to cold weather; issues related to compliance with environmental regulations; environmental hazards, such as natural gas leaks, oil and diesel spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized releases of brine, well stimulation and completion fluids, wastewater, toxic gases or other pollutants into the environment, especially those that reach surface water or groundwater; inadvertent third-party damage to our assets; and natural disasters. We also face various risks or threats to the operation and security of our or third parties' facilities and

infrastructure, such as processing plants, compressor stations and pipelines. Any of these risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property, equipment and natural resources, pollution or other environmental damage, loss of hydrocarbons, disruptions to our operations, regulatory investigations and penalties, suspension of our operations, repair and remediation costs, and loss of sensitive confidential information. Moreover, in the event that one or more of these hazards occur, there can be no assurance that a response will be adequate to limit or reduce damage.

As a result of these risks, we are also sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that the insurance policies we maintain to limit our liability for such losses will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices or to cover all risks. In addition, pollution and environmental risks generally are not fully insurable, and we may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of an event that is not fully covered by insurance could materially adversely affect our business, results of operations, cash flows and financial position.

Additionally, our investment in midstream infrastructure development and maintenance programs is intended, among other items, to connect our wells to other existing gathering and transmission pipelines and can involve significant risks, including those relating to timing, cost overruns and operational efficiency. Significant portions of our natural gas production are dependent on a small number of key compression and processing stations. An operational issue at any of those stations would materially impact our production, cash flow and results of operation.

A terrorist attack or armed conflict targeting our systems or natural gas infrastructure generally could materially adversely impact our operations.

Growing geopolitical instability and armed conflicts (including between Russia and Ukraine and in the Middle East) has resulted in energy infrastructure becoming a more prominent target of attack by terrorists and conflicting countries. Natural gas, NGLs and oil related facilities, including those operated by us or our service providers, could be direct targets of physical or cyber-attacks, and, if infrastructure integral to our operations is destroyed or damaged, we may experience a significant disruption in our operations. Any such disruption could materially adversely affect our financial condition, results of operations and cash flows. Costs for insurance and other security may increase as a result of increased threats, and certain insurance coverage may become more difficult to obtain, if available at all.

Potential physical effects of climate change could disrupt our production, transmission and processing activities, cause us to incur significant costs in preparing for or responding to those effects, or otherwise adversely affect our business.

Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere produce climate changes that may have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events. If any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our operations. Potential adverse effects could include disruption of our production activities; delays in getting our produced natural gas and NGLs to market or possibly shut-in as a result of physical damage to pipelines, other midstream infrastructure and processing facilities; increases in our costs of operation or reductions in the efficiency of our operations; reduced availability of electrical power, road accessibility, and transportation facilities; impacts on our personnel, supply chain, distribution chain or customers; and potentially increased costs for insurance coverages in the aftermath of such effects. Such physical effects could also adversely affect or delay demand for our products or cause us to incur significant costs in preparing for, or responding to, the effects of climatic or weather events themselves. Further, energy demand could increase or decrease as a result of extreme weather conditions. A decrease in energy use due to weather or climatic changes may affect our financial condition through decreased revenues. Any one of these factors has the potential to have a material adverse effect on our business, financial condition, results of operations, and cash flow. Our ability to mitigate the physical impacts of adverse weather conditions depends in part upon our disaster preparedness and response along with our business continuity planning.

Our drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of when they are drilled, if at all.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices; the

availability and cost of capital; drilling and production costs; the availability of drilling services and equipment; drilling results; lease expirations; topography; gathering system and pipeline transportation costs and constraints; access to and availability of sand and water and corresponding materials sourcing and distribution systems, including railroads; coordination with coal mining; regulatory approvals; and other factors. Because of these uncertain factors, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce natural gas, NGLs or oil from these or any other drilling locations. In addition, if production is not established within the spacing units covering our undeveloped acres in accordance with the requisite timeframe set forth in the applicable lease, our leases for such acreage will expire. Further, certain of the horizontal wells we intend to drill in the future may require pooling or unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to pool or unitize such leaseholds with ours, the total locations we can drill may be limited. As such, our actual drilling activities may materially differ from those presently identified.

Failure to timely develop our leased real property could result in increased capital expenditures and/or impairment of our leases.

Mineral rights are typically owned by individuals who may enter into property leases with us to allow for the development of natural gas. Such leases expire after an initial term, typically five years, unless certain actions are taken to preserve the lease. If we cannot preserve a lease, the lease terminates. Approximately 7% of our net undeveloped acres are subject to leases that could expire over the next three years. Lack of access to capital, changes in government regulations, changes in future development plans or commodity prices, reduced drilling activity, or the reduction in the fair value of undeveloped properties in the areas in which we operate could impact our ability to preserve, trade or sell our leases prior to their expiration, resulting in the termination or impairment of leases for properties that we have not developed.

We evaluate capitalized costs of unproved oil and gas properties at least annually to determine recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in our business strategy and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches and drilling activity has not commenced. For the years ended December 31, 2023, 2022 and 2021, we recorded impairment and expiration of leases of \$109.4 million, \$176.6 million and \$311.8 million, respectively. Refer to Note 1 to the Consolidated Financial Statements.

We may incur losses as a result of title defects in the properties in which we invest or the loss of certain leasehold or other rights related to our midstream activities.

Our inability to cure any title defects in our leases in a timely and cost-efficient manner may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase our production and reserves. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial position.

Additionally, most of the land on which our midstream systems have been constructed is not owned in fee by us; rather, the properties are held by surface use agreements, rights-of-way or other easement rights. We are, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew the right-of-way or for other reasons, could materially adversely affect our business, financial condition, results of operations and cash flows.

The amount and timing of actual future natural gas, NGLs and oil production is difficult to predict and may vary significantly from our estimates, which may reduce our earnings.

Because the rate of production from natural gas and oil wells, and associated NGLs, generally declines as reserves are depleted, our future success depends upon our ability to develop additional reserves that are economically recoverable and to optimize existing well production, and our failure to do so may reduce our earnings. Additionally, a failure to effectively and efficiently operate existing wells may cause our production volume to fall short of our projections. Our drilling and subsequent maintenance of wells can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, leases, rigs, equipment, a qualified work force, and adequate capacity for the treatment and recycling or disposal of wastewater generated in our operations, as well as weather conditions, natural gas, NGLs and oil price volatility, regulatory approvals, title and property access problems, geology, equipment failure or accidents and other factors. Drilling for natural gas and oil can be unprofitable, not only due to dry wells, but also as a result

of productive wells that perform below expectations or that do not produce sufficient revenues to return a profit. Low natural gas, NGLs and oil prices may further limit the types of reserves that we can develop and produce economically.

Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Our future natural gas, NGLs and oil production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot be certain that we will be able to find or acquire and develop additional reserves at an acceptable cost. Without continued successful development or acquisition activities, together with efficient operation of existing wells, our reserves and production, together with associated revenues, will decline as a result of our current reserves being depleted by production.

Our proved reserves are estimates that are based on many assumptions that may prove to be inaccurate. Any significant change in these underlying assumptions will greatly affect the quantities and present value of our reserves.

Reserve engineering is a subjective process involving estimates of underground accumulations of natural gas, NGLs and oil and assumptions concerning future prices, production levels and operating and development costs, some of which are beyond our control. These estimates and assumptions are inherently imprecise, and we may adjust our estimates of proved reserves based on changes in these estimates or assumptions. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any significant variance from our assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGLs and oil, the classifications of reserves based on risk of recovery and estimates of future net cash flows. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we believe our estimates are reasonable, actual production, revenues and costs to develop reserves will likely vary from our estimates and these variances could be material. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas, NGLs and oil we ultimately recover being different from our reserve estimates.

The standardized measure of discounted future net cash flows from our proved reserves is not the same as the current market value of our estimated natural gas, NGLs and oil reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated natural gas, NGLs and oil reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the twelve-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our reserves will be affected by factors such as the actual prices we receive for natural gas, NGLs and oil, the amount, timing and cost of actual production and changes in governmental regulations or taxation. The timing of both our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating the standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the natural gas, NGLs and oil industry in general.

Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy may result in additional write-downs of the carrying amounts of our assets, including long-lived intangible assets, which could materially and adversely affect our results of operations in future periods.

We review the carrying values of our assets for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. A significant amount of judgment is involved in performing these evaluations because the results are based on estimated future events and estimated future cash flows. The estimated future cash flows used to test our proved oil and gas properties for recoverability are based on proved and, if determined reasonable by management, risk-adjusted probable reserves, utilizing assumptions generally consistent with the assumptions used by our management for internal planning and budgeting purposes. Key assumptions used in our analyses include, among other things, the intended use of the asset, the anticipated production from reserves, future market prices for natural gas, NGLs and oil, future operating and development costs, inflation and the anticipated proceeds that may be received upon divestiture if there is a possibility that the asset will be divested prior to the end of its useful life. Commodity pricing is estimated by using a combination of the five-year NYMEX forward strip prices and assumptions related to gas quality, locational basis adjustments and inflation. Proved oil and

gas properties that have carrying amounts in excess of estimated future cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value.

Future declines in natural gas, NGLs or oil prices, increases in operating costs or adverse changes in well performance, among other circumstances, may result in our having to make significant future downward adjustments to our estimated proved reserves and/or could result in additional non-cash impairment charges to write-down the carrying amount of our assets, including other long-lived intangible assets, which may have a material adverse effect on our results of operations in future periods. Any impairment of our assets, including other long-lived intangible assets, would require us to take an immediate charge to earnings. Such charges could be material to our results of operations and could adversely affect our results of operations and financial position. See "Critical Accounting Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our significant accounting policies and assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties.

Financial and Market Risks Applicable to Our Business

Natural gas, NGLs and oil prices are affected by a number of factors beyond our control, including many of which that are unknown and cannot be anticipated, and we cannot predict with certainty future potential movements in the price for these commodities.

Our primary business involves the exploration, production and sale of hydrocarbons, and in particular, natural gas. Consequently, our revenue, profitability, future rate of growth, liquidity and financial position depend upon the market prices for natural gas and, to a lesser extent, NGLs and oil. Because our production and reserves predominantly consist of natural gas (approximately 93% of our equivalent proved developed reserves), changes in natural gas prices have significantly greater impact on our financial results than oil prices.

The prices for natural gas, NGLs and oil have historically been volatile and have been particularly volatile in recent years. The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of \$3.78 per MMBtu to a low of \$1.74 per MMBtu between the period from January 1, 2023 through December 31, 2023, and the daily spot prices for NYMEX West Texas Intermediate oil ranged from a high of \$93.67 per barrel to a low of \$66.61 per barrel during the same period. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. We expect commodity price volatility to continue or increase in the future due to rising macroeconomic uncertainty and geopolitical tensions.

Commodity prices are affected by a number of factors beyond our control, which include:

- weather conditions and seasonal trends;
- the domestic and foreign supply of and demand for natural gas, NGLs and oil;
- prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices (the market price for natural gas in the Appalachian Basin is typically lower relative to NYMEX Henry Hub as a result of the increased production and supply of natural gas in the Northeast United States);
- national and worldwide economic and political conditions, particularly those in, or affecting, other countries which are significant producers of natural gas and/or oil;
- new and competing exploratory finds of natural gas, NGLs and oil;
- changes in U.S. exports of natural gas, NGLs and oil;
- the effect of energy conservation efforts;
- the price, availability and consumer demand for alternative fuels;
- the availability, proximity, capacity and cost of pipelines, other transportation facilities, and gathering, processing and storage facilities and other factors that result in differentials to benchmark prices;
- technological advances affecting energy consumption and production;
- the actions of the Organization of Petroleum Exporting Countries;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- the cost of exploring for, developing, producing and transporting natural gas, NGLs and oil;
- risks associated with drilling, completion and production operations; and
- domestic, local and foreign governmental regulations, tariffs and taxes, including environmental and climate change regulation.

We use financial models to attempt to project future prices for the hydrocarbons we produce and sell, and we make decisions regarding our production, operations and hedging strategy in part based on such modelling. However, due to the volatility of commodity prices and the multitude of external factors that impact commodity prices, many of which are unknown and unforeseeable, we are unable to predict with certainty future potential movements in the market prices for natural gas, NGLs and oil. The success of our plans and strategies could be negatively affected if our projections of future hydrocarbon prices are significantly different from the ultimate actual price.

Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect on our revenue, profitability, future rate of growth, liquidity and financial position.

Prolonged low, and/or significant or extended declines in, natural gas, NGLs and oil prices may adversely affect our revenues, operating income, cash flows, financial projections, and financial position, particularly if we are unable to control our development costs during periods of lower natural gas, NGLs and oil prices. Declines in prices could also adversely affect our drilling activities and the amount of natural gas, NGLs and oil that we can produce economically, which may result in our having to make significant downward adjustments to the value of our assets and could cause us to incur non-cash impairment charges to earnings. Reductions in cash flows from lower commodity prices may require us to incur additional debt or reduce our capital spending, which could reduce our production and our reserves, negatively affecting our future rate of growth. Reduced cash flows could also result in us having to make downward adjustments to our financial projections, such as free cash flow, and could cause us to revise our shareholder returns initiatives, including the amount of dividends paid on our common stock, which could negatively impact the price of our common stock and our ability to access the capital markets. Lower prices for natural gas, NGLs and oil may also adversely affect our credit ratings and result in a reduction in our borrowing capacity and access to other capital. See "Critical Accounting Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our significant accounting policies and assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties.

Increases in natural gas, NGLs and oil prices may be accompanied by or result in increased well drilling costs, increased production taxes, increased lease operating expenses, increased volatility in seasonal gas price spreads for our storage assets and increased end-user conservation or conversion to alternative fuels. Significant natural gas price increases may subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including swap, collar and option agreements and exchange-traded instruments), which would potentially require us to post significant amounts of cash collateral or letters of credit with our hedge counterparties and would negatively impact our liquidity. The cash collateral provided to our hedge counterparties, which is interest-bearing, is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract. To the extent we have hedged our current production at prices below the current market price, we will not benefit fully from an increase in the price of natural gas.

Additionally, in recent years, volatility in natural gas prices and prolonged periods of high market prices for natural gas have led to calls by certain politicians to impose a windfall profits tax on natural gas producers, limit or prohibit the volume of LNG exports out of the United States and similar restrictive regulations on natural gas development and sales. While no such regulations have been passed in the United States, continued natural gas price volatility or prolonged high natural gas prices could result in the imposition of certain regulations directed at driving down the market price for natural gas. In the event such regulations are adopted, the price at which we sell our natural gas may be negatively impacted, thereby impacting our sales volume and operating revenues.

We are also exposed to the risk of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in our derivative contracts having a positive fair value in our favor. Further, adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our hedge counterparties to be unable to perform their obligations or to seek bankruptcy protection.

A financial crisis or deterioration in general economic, business or geopolitical conditions could materially adversely affect our operations and financial condition.

Concerns over global economic conditions, stock market volatility, energy costs, geopolitical issues (including continued hostilities between Russia and Ukraine as well as other conflicts, including in the Middle East), inflation and U.S. Federal Reserve interest rate increases in response thereto, the availability and cost of credit, and slowing of economic growth in the United States and abroad and fears of a recession have contributed and may continue to contribute to increased economic uncertainty and diminished expectations for the global economy. Global economic conditions, geopolitical issues and inflation

have constrained global and domestic supply chains, which has impacted and could in the future continue to impact our ability to develop our reserves in accordance with our drilling and completions schedule. Additionally, global economic conditions have a significant impact on commodity prices and any stagnation or deterioration in global economic conditions could result in decreased demand and, thus, lower prices for natural gas, NGLs or oil. Such uncertainty could also result in higher natural gas, NGLs and oil prices, which could potentially result in increased inflation worldwide and could negatively impact demand for natural gas, NGLs and oil.

Developments related to climate change may expedite a transition away from the use of carbon-intensive sources for energy generation and products derived from certain fossil fuels, which could have a material and adverse effect on us if we are not able to demonstrate that our products align with a low-carbon transition.

Governmental and regulatory bodies, investors, consumers, industry participants and other stakeholders have been increasingly focused on combating the effects of climate change. This focus, together with changes in consumer, industrial and commercial behavior, preferences and attitudes with respect to the generation and consumption of energy, and the use of products manufactured with, or powered by, fossil fuels, has led to, and in the long-term is anticipated to continue to result in, (i) the enactment of climate change-related regulations, policies and initiatives, (ii) technological advances with respect to the generation, transmission, storage and consumption of energy, and (iii) increased consumer, industrial and commercial demand for low-carbon energy sources and products manufactured with, or powered by, demonstrably low carbon-intensive sources. This has in turn led to increased scrutiny over the carbon-intensity of various fossil fuels, including the natural gas and NGLs that we produce and sell. If we are not able to demonstrate that our products align with a transition to a low-carbon economy, the demand and prices for our products could be negatively impacted depending on the pace of such transition and potential future demands for low-carbon products. Such developments may also adversely impact, among other things, the availability of third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Climate change-related developments may also impact the market prices of, or our access to, raw materials such as energy and water and therefore result in increased costs to our business.

Further, there have been efforts in recent years to influence the investment community, including investment advisors, insurance companies, and certain sovereign wealth, pension and endowment funds and other groups, by promoting divestment of fossil fuel equities and pressuring lenders to limit funding and insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Financial institutions may elect in the future to shift some or all of their investment into non-fossil fuel related sectors. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Ultimately, the foregoing factors could make it more difficult to secure funding for exploration and production activities or adversely impact the cost of capital for both us and our customers, and could thereby adversely affect the demand and price of our securities. Limitation of investments in and financings for energy companies could also result in the restriction, delay or cancellation of infrastructure projects and energy production activities.

Finally, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

We may not be able to successfully execute our plan to deleverage our business or otherwise reduce our debt level.

We have published a leverage and debt retirement strategy with the ultimate goal of reducing our absolute debt to \$3.5 billion (our Debt Retirement Plan). We intend to fund our Debt Retirement Plan through free cash flow, and have aligned our hedge strategy in a manner that we believe will mitigate the risk of volatility of future natural gas and NGLs prices, which we anticipate will enable us to execute on our Debt Retirement Plan and other capital allocation strategies; however, there can be no assurance that we will be able to generate sufficient free cash flow to execute our Debt Retirement Plan on our anticipated timeframe, if at all. If we are not able to successfully execute our Debt Retirement Plan or otherwise reduce our total debt to a level we believe appropriate, our credit ratings may be lowered, we may reduce or delay our planned capital expenditures or investments, and we may revise our shareholder returns strategy or other strategic plans.

Our operations have substantial capital requirements, and we may not be able to obtain needed capital or financing on satisfactory terms.

Our business is capital intensive. We make and expect to continue to make substantial capital expenditures for the development and acquisition of natural gas, NGLs and oil reserves, as well as processing facilities, pipelines and related infrastructure. Additionally, the construction of additions or modifications to our existing midstream systems involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If these projects are undertaken, they may not be completed on schedule, at the budgeted cost or at all. The construction of additions to our existing assets may require us to obtain new land rights and regulatory permits prior to constructing new pipelines or facilities, which may not be obtained in a timely, cost-effective fashion or in a way that allows us to connect new natural gas supplies to existing gathering pipelines or capitalize on other attractive expansion opportunities.

We typically fund our capital expenditures with existing cash and cash generated by operations and, to the extent our capital expenditures exceed our cash resources, from borrowings under our revolving credit facility and other external sources of capital. If we do not have sufficient borrowing availability under our revolving credit facility, we may seek alternate debt or equity financing, sell assets or reduce our capital expenditures. The issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures, shareholder returns initiatives and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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

- our level of proved reserves and production;
- the level of hydrocarbons we are able to produce from existing wells;
- our access to, and the cost of accessing, end markets for our production;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to access the public or private capital markets or borrow under our revolving credit facility.

If our cash flows from operations or the borrowing capacity under our revolving credit facility are insufficient to fund our capital expenditures and we are unable to obtain the capital necessary for our planned capital budget or our operations, we could be required to curtail our operations and the development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, results of operations and financial position.

As of December 31, 2023, our senior notes were rated "Baa3" with a "stable" outlook by Moody's Investors Services (Moody's), "BBB-" with a "stable" outlook by Standard & Poor's Ratings Service (S&P) and "BBB-" with a "stable" outlook by Fitch Ratings Service (Fitch). Although we are not aware of any current plans of Moody's, S&P or Fitch to downgrade its rating of our senior notes, we cannot be assured that one or more of these rating agencies will not downgrade or withdraw entirely its rating of our senior notes. Low prices for natural gas, NGLs and oil, an increase in the level of our indebtedness or other factors may result in Moody's, S&P or Fitch downgrading its rating of our senior notes. Changes in credit ratings may affect our access to the capital markets, the cost of short-term debt through interest rates and fees under our lines of credit, the interest rate on our revolving credit facility and Term Loan Facility (defined in Note 8 to the Consolidated Financial Statements) and senior notes with adjustable rates, the rates available on new long-term debt, our pool of investors and funding sources, the borrowing costs

and margin deposit requirements on our OTC derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts.

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

As of December 31, 2023, we had approximately \$5.8 billion of debt outstanding, and we may incur additional indebtedness in the future. Increases in our level of indebtedness may:

- require us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making certain investments and paying dividends;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- depending on the levels of our outstanding debt, limit our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and
- increase our vulnerability to downturns in our business or the economy, including declines in prices for natural gas, NGLs and oil.

Our debt agreements also require us to comply with certain covenants. If the price that we receive for our natural gas, NGLs and oil production deteriorates from current levels and continues for an extended period, it could lead to reduced revenues, cash flow and earnings, which in turn could lead to a default due to lack of covenant compliance. For more information about our debt agreements, read "Capital Resources and Liquidity" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations."

We are subject to financing and interest rate exposure risks.

Our business and operating results can be adversely affected by increases in interest rates or other increases in the cost of capital resulting from a reduction in our credit rating or otherwise. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flows used for operating and capital expenditures and place us at a competitive disadvantage.

Disruptions or volatility in the financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in the availability of credit could materially and adversely affect our ability to implement our business strategy and achieve favorable operating results. In addition, we are exposed to credit risk related to our revolving credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing line of credit if it experiences liquidity problems.

Derivative transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we currently and may in the future enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. Such hedges are designed to lock in prices in order to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge, and we may be required to post cash collateral or letters of credit with our hedge counterparties to the extent our liability under the derivative contract exceeds specified thresholds, which would negatively impact our liquidity. We have previously sustained losses as a result of certain of our derivative arrangements (including a loss on derivatives of \$4.6 billion and \$3.8 billion in 2022 and 2021, respectively), and we cannot assure you that we will not do so in the future. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected or an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas, NGLs or oil sales price.

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

Derivative transactions also expose us to a risk of financial loss if a counterparty fails to perform under a derivative contract or enters bankruptcy or encounters some other similar proceeding or liquidity constraint. In this case, we may not be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. During periods of falling commodity prices our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Risks Associated with Our Human Capital, Technology and Other Resources and Service Providers

Strategic determinations, including the allocation of resources to strategic opportunities, are challenging, and our failure to appropriately allocate resources among our strategic opportunities may adversely affect our financial position and reduce our future prospects.

Our future prospects are dependent upon our ability to identify optimal strategies for our business. Our operational strategy focuses on developing several multi-well pads in tandem through a process known as combo-development. We have allocated a substantial portion of our financial, human capital and other resources to pursuing this strategy, including investing in new technologies and equipment, restructuring our workforce, and pursuing various ESG and energy transition initiatives geared towards enhancing our strategy. We may not realize some or any of the anticipated strategic, financial, operational, environmental and other anticipated benefits from our operational strategy and the corresponding investments we have made in pursuing our strategy. Additionally, we cannot be certain that we will be able to successfully execute combo-development projects at the pace and scale that we project, which may delay or reduce our production and our reserves, negatively affecting our associated revenues. If we fail to identify and successfully execute optimal business strategies, including the appropriate operational strategy and corresponding initiatives, or fail to optimize our capital investments and the use of our other resources in furtherance of optimal business strategies, our financial position and growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Cyber incidents targeting our digital work environment or other technologies or energy infrastructure may adversely impact our operations.

Our business and the natural gas industry in general have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications, and the maintenance of our financial and other records has long been dependent upon such technologies. We depend on this technology to record and store data, estimate quantities of natural gas, NGLs and oil reserves, analyze and share operating data and communicate internally and externally. Computers and mobile devices control nearly all of the natural gas, NGLs and oil distribution systems in the U.S., which are necessary to transport our products to market.

The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber or other security or physical threats, and the continuing armed conflict between Russia and Ukraine and associated economic sanctions on Russia may have increased the likelihood of such threats. We can provide no assurance that we will not suffer such attacks in the future. Deliberate attacks on, or unintentional events affecting, our digital work environment or other technologies and infrastructure, the systems or infrastructure of third parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery of natural gas, NGLs and oil, difficulty in completing and settling transactions, challenges in maintaining our books and records, communication interruptions, environmental damage, personal injury, property damage, other operational disruptions and third-party liability. Further, as cyber incidents continue to evolve and cyber attackers become more sophisticated, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. The cost to remedy an unintended dissemination of sensitive information or data may be significant. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

The unavailability or high cost of additional drilling rigs, completion services, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages or higher costs. Historically, there have been shortages of personnel and equipment as demand for personnel and equipment has increased along with the number of wells being drilled. We cannot

predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could materially adversely affect our business, results of operations, cash flows and financial position.

Our ability to drill for and produce natural gas is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling services at a reasonable cost and in accordance with applicable environmental rules. Restrictions on our ability to obtain water or dispose of produced water and other waste may adversely affect our results of operations, cash flows and financial position.

The hydraulic fracture stimulation process on which we depend to drill and complete natural gas wells requires the use and disposal of significant quantities of water. Our ability to access sources of water and the availability of disposal alternatives to receive all of the water produced from our wells and used in hydraulic fracturing may affect our drilling and completion operations. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, or to timely obtain water sourcing permits or other rights, could adversely affect our operations. Additionally, the imposition of new, or modification of existing, environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste, which would adversely affect our business and results of operations, which could result in decreased cash flows.

In addition, federal and state regulatory agencies have investigated the possible connection between the operation of injection wells used for natural gas and oil waste disposal and increased seismic activity in certain areas. In some cases, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volume or suspend operations. Increased regulation and attention given to induced seismicity in the states where we operate could lead to restrictions on our disposal well injection volume and increased scrutiny of and delay in obtaining new disposal well permits, which could result in increased operating costs that could be material, or a curtailment of our operations.

The loss of key personnel could adversely affect our ability to execute our strategic, operational and financial plans.

Our operations are dependent upon 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, the success of our operations will depend, in part, on our ability to identify, attract, develop and retain experienced personnel. There is competition within our industry for experienced technical personnel and certain other professionals, which could increase the costs associated with identifying, attracting and retaining such personnel. If we cannot identify, attract, develop and retain our technical and professional personnel or attract additional experienced technical and professional personnel, our ability to compete in our industry could be harmed.

We depend on third-party midstream providers for a significant portion of our midstream services, and our failure to obtain and maintain access to the necessary infrastructure to successfully deliver natural gas, NGLs and oil to market on competitive terms may adversely affect our earnings, cash flows and results of operations.

Our delivery of natural gas, NGLs and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities primarily owned by third parties, and our ability to contract with these third parties at competitive rates or at all. The capacity of transmission, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs and oil or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Competition for access to pipeline infrastructure within the Appalachian Basin is intense, and our ability to secure access to pipeline infrastructure on favorable economic terms could affect our competitive position.

Although we own and operate certain midstream infrastructure for our own use, we depend on third-party providers to provide us with access to additional midstream infrastructure to get a significant portion of our produced natural gas, NGLs and oil to market. To the extent these services are delayed or unavailable, we would be unable to realize revenue from wells served by such third-party infrastructure until suitable arrangements are made to market our production. Access to midstream assets may be unavailable due to market conditions or mechanical or other reasons. In addition, due to regulatory and economic constraints, construction of new pipelines and building of such infrastructure may occur more slowly. A lack of access to needed infrastructure, or an extended interruption of access to or service from third-party pipelines and facilities for any reason, including vandalism, terroristic acts, sabotage or cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as delays in producing and selling our natural gas, NGLs and oil.

Finally, in order to ensure access to certain midstream facilities, we have entered into agreements that obligate us to pay demand charges to various pipeline operators. We also have commitments with third parties for processing capacity. We may be obligated to make payments under these agreements even if we do not fully use the capacity we have reserved, and these payments may be significant.

The substantial majority of our midstream and water services are provided by one provider, Equitrans Midstream. Therefore, any regulatory, infrastructure or other events that materially adversely affect Equitrans Midstream's business operations will have a disproportionately adverse effect on our business and operating results as compared to similar events experienced by our other third-party service providers. Additionally, our midstream services contracts with Equitrans Midstream involve significant long-term financial and other commitments on our part, which hinders our ability to diversify our slate of midstream service providers and seek better economic and other terms for the midstream services that are provided to us. We have no control over Equitrans Midstream's business decisions and operations, and Equitrans Midstream is not under any obligation to adopt a business strategy that favors us.

Historically, we have received the substantial majority of our natural gas gathering, transmission and storage and water services from Equitrans Midstream. Additionally, on February 26, 2020, we executed a gas gathering agreement with a wholly-owned subsidiary of Equitrans Midstream (the Consolidated GGA), which, among other things, consolidated the majority of our prior gathering agreements with Equitrans Midstream and its subsidiaries into a single agreement, established a new fee structure for gathering and compression fees charged by Equitrans Midstream, increased our minimum volume commitments with Equitrans Midstream, committed certain of our remaining undedicated acreage to Equitrans Midstream and extended our and Equitrans Midstream's contractual obligations with each other to 2035. Because we have significant long-term contractual commitments with Equitrans Midstream, we expect to receive the majority of our midstream and water services from Equitrans Midstream for the foreseeable future. Therefore, any event, whether in our areas of operation or otherwise, that adversely affects Equitrans Midstream's operations, water assets, pipelines, other transportation facilities, gathering and processing facilities, financial condition, leverage, results of operations or cash flows will have a disproportionately adverse effect on our business and operating results as compared to similar events experienced by our other third-party service providers. Accordingly, we are subject to the business risks of Equitrans Midstream, including the following:

- federal, state and local regulatory, political and legal actions that could adversely affect Equitrans Midstream's and its subsidiaries operations, assets and infrastructure, including potential further delays associated with placing the Mountain Valley Pipeline in service;
- construction risks associated with the construction or repair of Equitrans Midstream's pipelines and other midstream infrastructure, such as delays caused by landowners or advocacy groups opposed to the natural gas industry, environmental hazards, adverse weather conditions, the performance of third-party contractors, the lack of available skilled labor, equipment and materials and the inability to obtain necessary rights-of-way or approvals and permits from regulatory agencies on a timely basis or at all (and maintain such rights-of-way, approvals and permits once obtained);
- cyber-attacks or acts of sabotage or terrorism that could cause significant damage or injury to Equitrans Midstream's personnel, assets or infrastructure or lead to extended interruptions of Equitrans Midstream's operations;
- risks associated with Equitrans Midstream failing to properly balance supply and demand for its services, on a short-term, seasonal and long-term basis, which could result in Equitrans Midstream being unable to provide its customers, including us, with sufficient access to pipeline and other midstream infrastructure and water services as needed; and
- risks associated with Equitrans Midstream's leverage and financial profile, which could result in Equitrans Midstream being financially deterred or prohibited from providing services to its customers, including us, on a timely basis or at all.

In addition, many of our midstream services obligations with Equitrans Midstream are "firm" commitments, under which we have reserved an agreed upon amount of pipeline or storage capacity with Equitrans Midstream regardless of the capacity that we actually use during each month, and we are generally obligated to pay a fixed, monthly charge, at an amount agreed upon in the contract. Because these obligations involve significant long-term financial and other commitments on our part, they could reduce our cash flow during periods of low prices for natural gas, NGLs and oil when we may have lower volumes of natural gas and NGLs and therefore less of a need for capacity and storage, or the market prices for such pipeline and storage capacity services may be lower than what we are contractually obligated to pay to Equitrans Midstream.

Substantially all of our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating primarily in one major geographic area.

Substantially all of our producing properties are geographically concentrated in the Appalachian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by, and costs associated with, governmental regulation, state and local political activities, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other weather-related conditions, interruption of the processing or transportation of natural gas, NGLs or oil and changes in state and local laws, judicial precedents, political regimes and regulations. Such conditions could materially adversely affect our results of operations and financial position.

In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third parties may engage in subsurface coal and other mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling operations or adversely impact third-party midstream activities on which we rely. In such event, our operations may be impaired or interrupted, and we may not be able to recover the costs incurred as a result of temporary shut-ins or the plugging and abandonment of any of our wells. Furthermore, the existence of mining operations near our properties could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, could cause delays or interruptions or prevent us from executing our business strategy, which could materially adversely affect our results of operations and financial position.

Further, insufficient takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas prices. The Appalachian Basin has experienced periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers such as us and production possibly being shut in. Although additional Appalachian Basin takeaway capacity has been added in recent years, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by accelerated drilling in the area in the short term.

Due to the concentrated nature of our portfolio of natural gas properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

Legal and Regulatory Risks

Negative public perception regarding us and/or our industry, and increasing scrutiny of environmental, social and governance (ESG) matters, could have an adverse effect on our business, financial condition, and results of operations and damage our reputation.

Our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. However, opposition towards oil and natural gas drilling and pipeline construction generally has been growing globally and is particularly pronounced in the U.S. Failure to successfully manage expectations across these varied stakeholder interests could erode our stakeholder trust and thereby affect our reputation. Negative public perception regarding us and/or our industry may adversely affect our ability to successfully carry out our operations and business strategy. Such negative perception could, for example, adversely affect our access to and cost of capital and lead to increased litigation and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new local, state and federal laws, regulations, guidelines and enforcement interpretations in safety, environmental, royalty and surface use areas. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, challenged or burdened by requirements that restrict our ability to profitably conduct our business. In addition, anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations, such as drilling and pipeline construction. If activism against oil and natural gas exploration and development persists or increases, there could be a material adverse effect on our business, financial condition and results of operations.

Moreover, while we publish voluntary disclosures regarding ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such

expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment towards us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and cost of capital. In addition, failure or a perception (whether or not valid) of failure to implement our ESG strategy or achieve sustainability goals and targets we have set, could damage our reputation, causing our investors or consumers to lose confidence in our company, and negatively impact our operations. Our continuing efforts to research, establish, accomplish and accurately report on the implementation of our ESG strategy, including any climate or other ESG goals, may also create additional operational risks and expenses and expose us to reputational, legal and other risks. For example, growing interest on the part of investors and regulators in ESG factors and increased demand for, and scrutiny of, ESG-related disclosure by stakeholders has also increased the risk that companies could be perceived as, or accused of, making inaccurate or misleading statements regarding their ESG-related claims, goals, targets, efforts or initiatives, often referred to as "greenwashing." Such perception or allegation could damage our reputation and result in litigation or regulatory actions.

Laws and regulations directed at restricting emissions of methane and other GHGs could result in increased operating costs and reduced demand for the natural gas, NGLs and oil that we produce.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, in recent years numerous laws and regulations have been adopted, and more are being considered, to regulate the emission of carbon dioxide, methane and other GHGs.

In November 2022 at COP27, the Biden Administration agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. In November 2023, the European Union reached a provisional political agreement on a regulation to track and reduce methane emissions in the energy sector. The regulation introduces new requirements for the oil and gas sectors to measure, report and verify methane emissions and implements mitigation measures to avoid such emissions. The regulation also introduces new methane reporting and verification measures required to be applied by exporters to the European Union by January 1, 2027 and "maximum methane intensity values" must be met by 2030. Each member state will have the power to impose administrative penalties for failure to comply with such regulation and the standard will be mandatory for supply contracts signed after the law takes effect. The U.S. federal government has correspondingly instituted several regulations and initiatives in alignment with the goal of reducing the U.S.'s methane and other GHG emissions. Most recently, at COP28, President Biden announced the EPA's final standards to reduce methane emissions from new and existing oil and gas sources. Additionally, at COP28, nearly 200 countries, including the United States, entered into an agreement that calls for actions towards achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, are to accelerate efforts towards the phase-down of unabated coal power, phase out certain fossil fuel subsidies, and take other measures directed at driving the transition away from fossil fuels in energy systems.

In recent years, the EPA has proposed and adopted amendments to existing rules as well as new rules directed at restricting the amount of methane and other GHG emissions from new and existing oil and natural gas production and natural gas processing and transmission facilities. See Item 1., "Business-Regulation-Air Emissions" for more information. These federal rulemakings and regulations could adversely affect our operations and restrict or delay our ability to obtain air permits.

At the U.S. federal level, in November 2021, Congress approved a \$1 trillion legislative infrastructure package known as the Inflation Reduction Act of 2022, which includes a number of climate-focused spending initiatives, including imposing a fee known as a "waste emission charge" on methane emissions from certain natural gas and oil facilities that are in excess of a specified threshold. In January 2024, the EPA proposed a rule implementing the IRA's methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the IRA. Further, in July 2023, the EPA proposed to expand the scope of emissions events that are reportable under the Greenhouse Gas Reporting Program for petroleum and natural gas systems (Subpart W), which may result in an increase in reported methane and other GHG emissions under Subpart W for many operators, including us. The rule is currently scheduled to be finalized in the spring of 2024 and would take effect on January 1, 2025.

Additionally, a number of U.S. state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of carbon taxes, policies and incentives to encourage the use of renewable energy or alternative low-carbon

fuels, the development of greenhouse gas incentives, cap-and-trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs.

Regulations requiring the disclosure of GHG emissions and other climate-related information or information substantiating climate-related claims are also increasingly being adopted or proposed at the federal and state level.

See Item 1., "Business-Regulation-Climate Change and Regulation of Methane and Other Greenhouse Gas Emissions" for more information.

It is not possible at this time to predict how legislation or regulations that may be adopted to reduce or restrict methane and other GHG emissions would impact our business. However, any legislation or regulatory programs at the international, federal, state or city levels designed to reduce methane or other GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas, NGLs and oil we produce. Existing laws and regulations and any future laws and regulations of this nature, including those imposing reporting obligations, or imposing a tax or fee or otherwise limiting emissions of methane or other GHGs from our equipment and operations could require us to incur costs to comply with such regulations, including costs to monitor and report on GHG emissions, install new equipment to reduce emissions of GHGs associated with our operations, acquire emissions allowances or comply with new regulatory requirements. Substantial limitations or taxes or fees on methane or other GHG emissions, as well as other regulatory incentives or requirements to conserve energy, use alternative sources or reduce GHG emissions in product supply chains, could also adversely affect demand for the natural gas, NGLs and oil we produce, stimulate demand for alternative forms of energy that do not rely on combustion of fossil fuels, and lower the value of our reserves.

We may also face increased litigation risks arising from climate-related disclosures required by regulations. In addition, enhanced climate disclosure could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. Consequently, legislation and regulatory programs addressing climate change or methane and other GHG emissions could have an adverse effect on our business, financial condition and results of operations.

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

Our exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of water and other fluids and materials, including solid and hazardous wastes, incidental to natural gas and oil operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances.

Our operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of properties. Some states allow the statutory pooling and unitization of tracts to facilitate development and exploration, as well as joint development of existing contiguous leases. In addition, state conservation and natural gas and oil laws generally limit the venting or flaring of natural gas and may set production allowances on the amount of annual production permitted from a well.

Environmental and occupational health and safety legal requirements govern discharges of substances into the air, ground and water; the management and disposal of hazardous substances and wastes; the clean-up of contaminated sites; groundwater quality and availability; plant and wildlife protection; locations available for drilling; environmental impact studies and assessments prior to permitting; restoration of drilling properties after drilling is completed; and work practices related to employee health and safety.

To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Maintaining compliance with the laws, regulations and other legal requirements applicable to our business and any delays in obtaining related authorizations may affect the costs and timing of developing our natural gas, NGLs and oil resources. These requirements could also subject us to claims for personal injuries, property damage and other damages. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs

could materially adversely affect our results of operations, cash flows and financial position. Our failure to comply with the laws, regulations and other legal requirements applicable to our business, even if as a result of factors beyond our control, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages as well as corrective action costs.

Changes in tax laws and regulations could adversely impact our earnings and the cost, manner or feasibility of conducting our operations.

We are subject to taxation by various governmental authorities at the federal, state and local levels in the jurisdictions in which we operate. New legislation could be enacted by these governmental authorities, which could increase our tax burden and increase the cost to produce natural gas. Members of Congress periodically introduce legislation to revise U.S. federal income tax laws which could have a material impact on us. In recent years, legislation has been proposed that would, if enacted, make significant changes to U.S. tax laws, including the reduction or elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions or credits that are currently available with respect to oil and natural gas exploration and development, which could adversely impact our earnings, cash flows and financial position. Additionally, state and local taxing authorities in jurisdictions in which we operate or own assets may enact new taxes, such as the imposition of a severance tax on the extraction of natural resources in states in which we produce natural gas, NGLs and oil, or change the rates of existing taxes, which could adversely impact our earnings, cash flows and financial position.

Our hedging activities are subject to numerous and evolving financial laws and regulations which could inhibit our ability to effectively hedge our production against commodity price risk or increase our cost of compliance.

We use financial derivative instruments to hedge the impact of fluctuations in natural gas, NGLs and oil prices on our results of operations and cash flows. As disclosed in Item 1., "Business-Regulation," the Dodd-Frank Act, the rules adopted thereunder and various other foreign regulations could increase the cost of our derivative contracts, alter the terms of our derivative contracts, reduce the availability of derivatives to protect against the price risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and lessen the number of available counterparties and, in turn, increase our exposure to less creditworthy counterparties. If our use of derivatives is reduced as a result of the Dodd-Frank Act, related regulations or such foreign regulations, our results of operations may become more volatile, and our cash flows may be less predictable, which could adversely affect our ability to plan for, and fund, our capital expenditure requirements. Any of these consequences could have a material adverse effect on our business, financial position and results of operations. We have experienced increased, and anticipate additional, compliance costs and changes to current market practices as participants continue to adapt to a changing financial regulatory environment.

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

We use hydraulic fracturing in the completion of our wells. Hydraulic fracturing typically is regulated by state natural gas and oil commissions, but the EPA prohibits the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Certain governmental reviews have been conducted or are underway that focus on the environmental aspects of hydraulic fracturing practices. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from constructing wells. See Item 1., "Business-Regulation-Environmental, Health and Safety Regulation" for more information.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment and occupational health and workplace safety, including regulations and enforcement policies that have tended to become increasingly strict over time, resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of clean-up and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and occupational health and workplace safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters.

In addition, new or additional laws and regulations, new interpretations of existing requirements or changes in enforcement policies could impose unforeseen liabilities, significantly increase compliance costs or result in delays of, or denial of rights to conduct, our development programs. For example, see Item 1., "Business-Regulation-Water Discharges" for information related to ongoing interpretation disputes under the CWA. To the extent a new rule or further litigation expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Such potential regulations or litigation could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which in turn could materially adversely affect our results of operations and financial position. Further, the discharges of natural gas, NGLs, oil, and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties.

Regulations related to the protection of wildlife could adversely affect our ability to conduct drilling activities and pipeline construction in some of the areas where we operate.

Our operations can be adversely affected by regulations designed to protect various wildlife, including threatened and endangered species and their critical habitat. The implementation of measures to protect wildlife or the designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in constraints on our exploration, production and midstream activities. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Risks Associated with Strategic Transactions

Entering into strategic transactions may expose us to various risks.

We periodically engage in acquisitions, dispositions and other strategic transactions, including joint ventures. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory and third-party approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; the assumption of, or retaining, potential environmental or other liabilities; and our ability to realize the benefits expected from the transactions. In addition, various factors, including prevailing market conditions, could negatively impact the benefits we receive from these transactions. With respect to dispositions in particular, various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. Competition for strategic transaction opportunities in our industry is intense and may increase the cost of, reduce the benefits from, or cause us to refrain from, completing such transactions.

Moreover, joint venture arrangements may restrict our operational and corporate flexibility. Joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little or partial control over, and our joint venture partners may not satisfy their obligations to the joint

venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

Securities class action and derivative lawsuits may be brought against us in connection with strategic transactions, which could result in substantial costs and may delay or prevent such transactions from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other business combination agreements. Even if such a lawsuit is without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Lawsuits that may be brought against us or our directors could also seek, among other things, injunctive relief or other equitable relief, including a request to enjoin us from consummating a strategic transaction. If a plaintiff is successful in obtaining an injunction prohibiting completion of a pending transaction, that injunction may delay or prevent a pending transaction from being completed within the expected timeframe or at all, which may adversely affect our business, financial position and results of operation.

Acquisitions may disrupt our current plans or operations and may not be worth what we pay 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 potential; future natural gas, NGLs and oil prices and their appropriate differentials; availability and cost of transportation of production to markets; availability and cost of drilling equipment and of skilled personnel; development and operating costs, including access to water; production taxes; potential environmental and other liabilities; and regulatory, permitting and similar matters. These assessments are complex and inherently imprecise. Our review of the properties and other assets we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well or lease that we acquire, and even when we inspect a well or lease, 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.

Also, our ability to achieve the anticipated benefits of an acquisition will depend in part upon whether we can integrate the acquired assets and their operations into our existing business in an efficient and effective manner. The integration process may be subject to delays or changed circumstances, and we can give no assurance that assets we acquire will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of an acquisition will materialize.

If there is a later determination that our spin-off of Equitrans Midstream or certain related transactions are taxable for U.S. federal income tax purposes because the facts, assumptions, representations or undertakings underlying the IRS private letter ruling and/or opinion of counsel are incorrect or for any other reason, significant liabilities could be incurred by us, our shareholders or Equitrans Midstream.

In connection with our 2018 spin-off of Equitrans Midstream as a separate, publicly-traded company, we obtained a private letter ruling from the IRS and an opinion of outside counsel regarding the qualification of the distribution of Equitrans Midstream shares to our shareholders (the Distribution), together with certain related transactions, as a transaction that is generally tax-free, for U.S. federal income tax purposes, under Sections 355 and 368(a)(1)(D) of the U.S. Internal Revenue Code, as amended, and certain other U.S. federal income tax matters relating to the Distribution and certain related transactions. The IRS private letter ruling and the opinion of counsel are based on and rely on, among other things, various facts and assumptions, as well as certain representations, statements and undertakings of us and Equitrans Midstream, including those relating to the past and future conduct of us and Equitrans Midstream. If any of these representations, statements or undertakings is, or becomes, inaccurate or incomplete, or if we or Equitrans Midstream breach any representations or covenants contained in any of the spin-off-related agreements and documents or in any documents relating to the IRS private letter ruling

and/or the opinion of counsel, we and our shareholders may not be able to rely on the IRS private letter ruling or the opinion of counsel.

Notwithstanding receipt of the IRS private letter ruling and the opinion of counsel, the IRS could determine on audit that the Distribution and/or certain related transactions should be treated as taxable transactions for U.S. federal income tax purposes if it determines that any of the representations, assumptions or undertakings upon which the IRS private letter ruling was based are false or have been violated or if it disagrees with the conclusions in the opinion of counsel that are not covered by the ruling or for other reasons. An opinion of counsel represents the judgment of such counsel and is not binding on the IRS or any court, and the IRS or a court may disagree with the conclusions in such opinion of counsel. Accordingly, notwithstanding receipt of the IRS private letter ruling and the opinion of counsel, there can be no assurance that the IRS will not assert that the Distribution and/or certain related transactions should be treated as taxable transactions or that a court would not sustain such a challenge. In the event the IRS were to prevail with such challenge, we, Equitrans Midstream and our shareholders could be subject to material U.S. federal and state income tax liabilities. In connection with the spin-off, we and Equitrans Midstream entered into a tax matters agreement, which described the sharing of any such liabilities between us and Equitrans Midstream.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

We maintain an Enterprise Risk Committee, composed of our Chief Financial Officer, General Counsel, Chief Information Officer and other members of senior management, which oversees the identification and management of corporate-level risks, including cybersecurity risk, using the COSO Enterprise Risk Management Framework. To support the identification of emerging risks and align our focus on our primary business risks, our Manager Enterprise Risk, whose job responsibilities are dedicated to enterprise risk management, surveys senior leaders at least annually to assess our most significant, or "Tier 1," enterprise risks. Based in part on this survey, our Enterprise Risk Committee assesses our most significant risks and considers the effectiveness of our risk mitigation efforts, and the Manager Enterprise Risk leads a presentation to our Board of Directors covering this information on an annual basis. Our Enterprise Risk Committee also oversees periodic follow-up assessments to analyze changes in existing, evolving and emerging risks and identify new or more effective measures for mitigation.

Cybersecurity risk was classified as a Tier 1 enterprise risk for our company by our Enterprise Risk Committee for 2023. Our Manager Enterprise Risk, with oversight by our Enterprise Risk Committee, facilitates the monitoring of all Tier 1 enterprise risks within our digital work environment for changes in risk drivers and supports the evaluation of the potential impacts of each Tier 1 enterprise risk on our company, taking into consideration the effectiveness of our identified risk mitigants.

As part of its regular oversight role, our Board of Directors, with a primary focus on policy, oversight and strategic direction, oversees management's development and maintenance of the enterprise cybersecurity program and its actions to identify, assess, mitigate and remediate cybersecurity threats to our company. Our Board of Directors has delegated to its Audit Committee primary responsibility for regular oversight of cybersecurity risk at the Board-level and this delegation is reflected in the Audit Committee's Charter. Our Chief Information Officer provides a regular quarterly report to the Audit Committee of our Board of Directors regarding cybersecurity matters and our enterprise cybersecurity program.

Our management-level Enterprise Risk Committee has delegated to our Chief Information Officer primary responsibility for identifying, assessing and managing cybersecurity-related risks. Our Chief Information Officer has a Bachelor of Science in Computer Science from the University of Kentucky and a Master of Business Administration in Finance from the Wharton School of Business at the University of Pennsylvania. He has served in his current role at EQT since 2019 and has over twenty years of information technology experience within the energy industry.

Our Information Security team, led by our Vice President, Information Technology, who reports directly to our Chief Information Officer, manages our enterprise cybersecurity program and is responsible for managing all reported cybersecurity threats and addressing matters related to cybersecurity risk, information security and technology risk.

We maintain a Cybersecurity Incident Management Policy (Cybersecurity Policy), which provides guidance and processes for identifying, reporting, assessing, resolving and ensuring timely public disclosure, when appropriate, of cybersecurity threats, including both cybersecurity threats directed at our company and those associated with our use of third-party service providers. We have retained a leading cybersecurity incident response vendor to assist us in responding to cybersecurity incidents and we maintain relationships with integration vendors to help us recover or rebuild technology systems in the event of a large-scale cybersecurity incident.

Our Cybersecurity Policy requires that all of our employees, contractors and vendors report any suspected cybersecurity threat to our Information Security team using reporting functions within our digital work environment. Once reported, our Information Security team begins investigating the incident and assigns an alert classification to the incident, based on the perceived level of threat to our company and our technology network. The team updates the alert classification, as appropriate, throughout the incident response process.

In the event our Information Security team classifies a cybersecurity incident as posing a "critical risk," our Disclosure Committee, which includes our General Counsel and Chief Accounting Officer, is immediately notified of such classification via functions within our digital work environment. The Disclosure Committee, in consultation with our Information Security team and Chief Information Officer, engages in an assessment of the materiality of the cybersecurity incident, under applicable disclosure standards, including material developments throughout the incident response process. Our Board of Directors would be promptly informed upon identification of any material cybersecurity event.

Our Information Security team is responsible for managing all reported cybersecurity threats until final resolution. We maintain a record of reported cybersecurity incidents and the management and resolution of such incidents.

Our Information Security team, with support from our Legal Department, annually reviews our Cybersecurity Policy to ensure alignment with cybersecurity best practices.

Cybersecurity threats, including as a result of any previous cybersecurity incidents, have not materially affected our company, including our business strategy, results of operations or financial condition. However, we face certain ongoing risks from cybersecurity threats that, if realized, may be reasonably likely to materially affect our operations and, therefore, our results of operations and/or financial condition. For more information about these risks, see Item 1A., "Risk Factors - Cyber incidents targeting our digital work environment or other technologies or energy infrastructure may adversely impact our operations."

Item 2. Properties

See Item 1., "Business" for a description of our properties. Our corporate headquarters is located in leased office space in Pittsburgh, Pennsylvania. We also own or lease office space in Pennsylvania, West Virginia and Texas.

Item 3. Legal Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against us. While the amounts claimed may be substantial, we are unable to predict with certainty the ultimate outcome of such claims and proceedings. We accrue legal and other direct costs related to loss contingencies when actually incurred. We have established reserves in amounts that we believe to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, we believe that the ultimate outcome of any pending matter involving us will not materially affect our financial position, results of operations or liquidity.

Item 4. Mine Safety Disclosures

Not Applicable.

Information about our Executive Officers (as of February 14, 2024)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Tony Duran (45)	Chief Information Officer (2019)	Mr. Duran was appointed as the Chief Information Officer of EQT Corporation in July 2019. Prior to joining EQT Corporation, Mr. Duran ran PH6 Labs, a technology incubator he founded, from December 2017 to July 2019. Prior to that, he served as the Chief Information Officer of Rice Energy Inc. (independent natural gas and oil company acquired by EQT Corporation in November 2017) from January 2016 to November 2017; and as the Interim Chief Information Officer of Express Energy Services (oilfield services company for well construction and well testing services) from September 2015 to December 2015. Additionally, Mr. Duran held various positions at National Oilwell Varco (multinational corporation that provides equipment and components used in oil and gas drilling and production operations, oilfield services, and supply chain integration services to the upstream oil and gas industry) from May 2002 to August 2015, where he last held the role of Assistant Chief Information Officer.
Lesley Evancho (46)	Chief Human Resources Officer (2019)	Ms. Evancho was appointed as the Chief Human Resources Officer of EQT Corporation in July 2019. Prior to joining EQT Corporation, Ms. Evancho served as Vice President, Global Talent Management at Westinghouse Electric Company, LLC (nuclear power, fuel and services company) from April 2019 to July 2019; Senior Director, Human Resources at Thermo Fisher Scientific, Inc. (biotechnology product development company) from August 2018 to March 2019; Vice President, Human Resources at Edward Marc Brands (food services company) from March 2018 to August 2018; and Vice President, Human Resources at Rice Energy Inc. from April 2017 to November 2017. Additionally, Ms. Evancho served as Global Director, Talent Management at MSA Safety, Inc. (manufacturer of industrial safety equipment) from November 2011 to April 2017.
Todd M. James (41)	Chief Accounting Officer (2019)	Mr. James was appointed as the Chief Accounting Officer of EQT Corporation in November 2019. Prior to joining EQT Corporation, Mr. James served as the Corporate Controller and Chief Accounting Officer of L.B. Foster Company (manufacturer and distributor of products and services for transportation and energy infrastructure) from April 2018 to October 2019. Prior to that he served as the Senior Director, Technical Accounting and Financial Reporting at Rice Energy Inc. from December 2014 through its acquisition by EQT Corporation in November 2017 and until February 2018. Prior to joining Rice Energy, Mr. James was a Senior Manager, Assurance at PricewaterhouseCoopers LLP (public accounting firm), where he worked from August 2005 to November 2014.
William E. Jordan (43)	Executive Vice President, General Counsel and Corporate Secretary (2019)	Mr. Jordan was appointed as the Executive Vice President and General Counsel of EQT Corporation in July 2019 and assumed the role of Corporate Secretary in November 2020. Mr. Jordan served as an advisor to the Rice Investment Group (multi-strategy investment fund investing in all verticals of the oil and gas sector) from May 2018 until July 2019. Prior to that, he served as the Senior Vice President, General Counsel and Corporate Secretary of Rice Energy Inc. and Senior Vice President, General Counsel and Corporate Secretary of Rice Midstream Partners LP (former midstream services affiliate of Rice Energy Inc.), in each case from January 2014 until their acquisition by EQT Corporation in November 2017. From September 2005 to December 2013, Mr. Jordan was an associate at Vinson & Elkins LLP (an international law firm) representing public and private companies in capital markets offerings and mergers and acquisitions, primarily in the oil and natural gas industry.
Jeremy T. Knop (35)	Chief Financial Officer (2023)	Mr. Knop was appointed as the Chief Financial Officer of EQT Corporation in July 2023. Prior to becoming Chief Financial Officer, Mr. Knop was responsible for the development and execution of EQT Corporation's mergers and acquisitions strategy, serving as Executive Vice President of Corporate Development beginning in March 2022 and as Senior Vice President of Corporate Development from January 2021 through March 2022. Prior to joining EQT Corporation, from August 2012 to January 2021, Mr. Knop was employed by The Blackstone Group (a global investment firm whose asset management business includes investment vehicles focused on real estate, private equity, infrastructure, life sciences, growth equity, credit, real assets and secondary funds), where he served in several capacities on the energy credit team, including as Principal from January 2019 to January 2021, Vice President from January 2017 to December 2018, Associate from January 2014 to December 2016, and Analyst from August 2012 to December 2013. Earlier in his career, Mr. Knop served as an Analyst in Global Natural Resources Investment Banking at Barclays Capital (a multinational investment bank) from June 2010 to August 2012.
Toby Z. Rice (42)	President and Chief Executive Officer (2019)	Mr. Rice was appointed as President and Chief Executive Officer of EQT Corporation in July 2019, when he also was elected to EQT Corporation's Board of Directors. Mr. Rice has served as a Partner at the Rice Investment Group, a multi-strategy fund investing in all verticals of the oil and gas sector, since May 2018. From October 2014 until its acquisition by EQT Corporation in November 2017, Mr. Rice was President and Chief Operating Officer of Rice Energy Inc. and served on the Board of Directors of Rice Energy Inc. from October 2013 to November 2017. Prior to that, he served in a number of positions with Rice Energy Inc., its affiliates and predecessor entities beginning in February 2007, including as President and Chief Executive Officer of a predecessor entity from February 2008 through September 2013. Mr. Rice is the brother of Daniel J. Rice IV, a member of EQT Corporation's Board of Directors since November 2017.

All executive officers have either elected to participate in the EQT Corporation Executive Severance Plan, which includes confidentiality and non-compete provisions, or executed non-compete agreements with EQT Corporation, and each of the executive officers serve at the pleasure of our Board of Directors. Officers are appointed annually to serve during the ensuing year or until their successors are elected and qualified, or until death, resignation or removal.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the New York Stock Exchange under the symbol "EQT."

As of February 9, 2024, there were 1,735 shareholders of record of our common stock.

On February 8, 2024, our Board of Directors declared a quarterly cash dividend of \$0.1575 per share of EQT Corporation common stock, payable on March 1, 2024, to shareholders of record at the close of business on February 20, 2024.

The amount and timing of dividends declared and paid by us, if any, are subject to the discretion of our Board of Directors and depends on business conditions, such as our results of operations and financial condition, strategic direction and other factors. Our Board of Directors has the discretion to change the dividend rate at any time for any reason.

Recent Sales of Unregistered Securities

We did not repurchase any equity securities registered under Section 12 of the Exchange Act during the three months ended December 31, 2023.

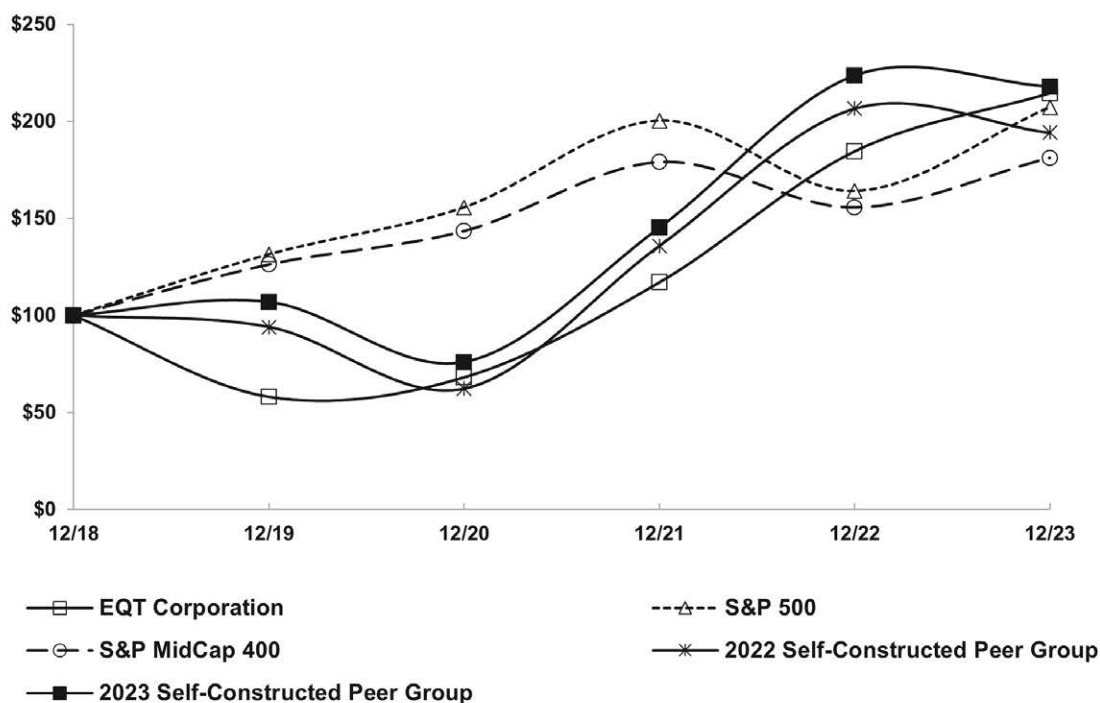
On December 13, 2021, we announced that our Board of Directors approved a share repurchase program (the Share Repurchase Program) authorizing us to repurchase shares of our outstanding common stock for an aggregate purchase price of up to \$1 billion, excluding fees, commissions and expenses. On September 6, 2022, we announced that our Board of Directors approved a \$1 billion increase to the Share Repurchase Program, pursuant to which approval we are authorized to repurchase shares of our outstanding common stock for an aggregate purchase price of up to \$2 billion, excluding fees, commissions and expenses. Repurchases under the Share Repurchase Program may be made from time to time in amounts and at prices we deem appropriate and will be subject to a variety of factors, including the market price of our common stock, general market and economic conditions, applicable legal requirements and other considerations. The Share Repurchase Program was originally scheduled to expire on December 31, 2023; however, on April 26, 2023, we announced that our Board of Directors approved a one-year extension of the Share Repurchase Program. As a result of such extension, the Share Repurchase Program will expire on December 31, 2024, but it may be suspended, modified or discontinued at any time without prior notice. As of December 31, 2023, we had purchased shares for an aggregate purchase price of \$622.1 million, excluding fees, commissions and expenses, under the Share Repurchase Program since its inception, and the approximate dollar value of shares that may yet be purchased under the Share Repurchase Program is \$1.4 billion.

Stock Performance Graph

The graph below compares the most recent cumulative five-year total return provided to shareholders of our common stock relative to the cumulative five-year total returns of the S&P 500 Index, the S&P MidCap 400 Index and two customized peer groups, the 2022 Self-Constructed Peer Group and the 2023 Self-Constructed Peer Group, whose company composition is discussed in footnotes (a) and (b), respectively, below. Our common stock was included in the S&P 500 Index until November 2018, at which time our common stock was added to the S&P MidCap 400 Index. Our common stock was added back to the S&P 500 Index in October 2022. Accordingly, we have presented both indices for comparison in the following graph. An investment of \$100, with reinvestment of all dividends, is assumed to have been made in our common stock, in the S&P 500 Index, the S&P MidCap 400 Index and in each of the peer groups on December 31, 2018 and its relative performance is tracked through December 31, 2023. The stock price performance shown in the graph below is not necessarily indicative of future stock price performance.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among EQT Corporation, the S&P 500 Index, the S&P MidCap 400 Index,
2022 Self-Constructed Peer Group and 2023 Self-Constructed Peer Group



*\$100 invested on 12/31/18 in stock, index or peer group, including reinvestment of dividends.
Fiscal year ending December 31.

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	12/18	12/19	12/20	12/21	12/22	12/23
EQT Corporation	\$ 100.00	\$ 58.18	\$ 68.21	\$ 117.05	\$ 184.46	\$ 214.36
S&P 500 Index	100.00	131.49	155.68	200.37	164.08	207.21
S&P MidCap 400 Index	100.00	126.20	143.44	178.95	155.58	181.15
2022 Self-Constructed Peer Group (a)	100.00	94.04	62.22	135.86	206.58	194.10
2023 Self-Constructed Peer Group (b)	100.00	106.87	75.96	145.21	223.56	217.88

- (a) The 2022 Self-Constructed Peer Group includes the following fourteen companies: Antero Resources Corp., APA Corp. (US), Chesapeake Energy Corp., CNX Resources Corp., Comstock Resources, Inc., Coterra Energy Inc., Devon Energy Corp., Diamondback Energy, Inc., Marathon Oil Corp., Matador Resources Co., Murphy Oil Corp., Ovintiv Inc., Range Resources Corp. and Southwestern Energy Co. The 2022 Self-Constructed Peer Group is comprised of the companies included in our 2022 performance peer group (with the exception of (i) Continental Resources, Inc., which was excluded for purposes of the stock performance graph because its stock ceased to be publicly traded beginning in November 2022, and (ii) PDC Energy Inc., which was excluded for purposes of the stock performance graph because it was acquired by Chevron Corp. in August 2023), as selected by the Management Development and Compensation Committee of our Board of Directors for purposes of evaluating our relative total shareholder return under the 2022 Incentive Performance Share Unit Program.
- (b) The 2023 Self-Constructed Peer Group includes the following sixteen companies: Antero Resources Corp., APA Corp. (US), Chesapeake Energy Corp., CNX Resources Corp., Comstock Resources Inc., Coterra Energy Inc., Devon Energy Corp., Diamondback Energy, Inc., Hess Corp., Marathon Oil Corp., Matador Resources Co., Murphy Oil Corp., Ovintiv Inc., Pioneer Natural Resources Co., Range Resources Corp. and Southwestern Energy Co. The 2023 Self-Constructed Peer Group is comprised of the companies included in our 2023 performance peer group (with the exception of PDC Energy Inc., which was excluded for purposes of the stock performance graph because it was acquired by Chevron Corp. in August 2023), as selected by the Management Development and Compensation Committee of our Board of Directors for purposes of evaluating our relative total shareholder return under the 2023 Incentive Performance Share Unit Program.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of financial condition and results of operations should be read in conjunction with the Consolidated Financial Statements and the notes thereto included in Item 8., "Financial Statements and Supplementary Data."

Consolidated Results of Operations

Net income attributable to EQT Corporation for 2023 was \$1,735 million, \$4.22 per diluted share, compared to \$1,771 million, \$4.38 per diluted share, for 2022. The decrease was attributable primarily to decreased sales of natural gas, NGLs and oil, partly offset by a gain on derivatives in 2023 compared to a loss on derivatives in 2022, impairment of the contract asset (discussed in Note 5 to the Consolidated Financial Statements) in 2022, decreased income tax expense and a loss on debt extinguishment in 2022.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on Form 10-K for the year ended December 31, 2022, which is incorporated herein by reference, for discussion and analysis of consolidated results of operations for the year ended December 31, 2021.

Results of operations for the period beginning August 22, 2023 through December 31, 2023 include the results of our operation of assets acquired in the Tug Hill and XcL Midstream Acquisition. See Note 6 to the Consolidated Financial Statements for further discussion of the Tug Hill and XcL Midstream Acquisition.

See "Sales Volume and Revenues" and "Operating Expenses" for discussions of items affecting operating income and "Other Income Statement Items" for a discussion of other income statement items. See "Investing Activities" under "Capital Resources and Liquidity" for a discussion of capital expenditures.

Trends and Uncertainties

Our sales volume and operating expenses on a per Mcfe basis during the first half of 2023 were negatively impacted by fewer wells turned-in-line during 2022 compared to our 2022 planned development schedule due to third-party supply chain constraints. In addition, as a result of third-party supply chain constraints in 2022, we shifted the planned development of approximately 30 wells from 2022 to 2023 (the Rescheduled Wells). All of the Rescheduled Wells were completed and turned-to-sales as of July 2023, resulting in our third quarter 2023 sales volumes returning to our normalized level of production; however, our sales volume during the second half of 2023 was negatively impacted by approximately 13 Bcfe of curtailments (inclusive of non-operated wells in which we have a working interest) principally in response to lower natural gas prices in the Appalachian Basin. Future supply chain constraints or declines in natural gas prices may result in adjustments to our 2024 planned development schedule or the development schedule of non-operated wells in which we have a working interest. Further, we cannot control or otherwise influence the development schedule of non-operated wells in which we have a working interest. Adjustments to our 2024 planned development schedule or the development schedule of non-operated wells in which we have a working interest, including due to declines in natural gas prices, the pace of well completions, access to sand and water to conduct drilling operations, access to sufficient pipeline takeaway capacity, unscheduled downtime at processing facilities or otherwise, could impact our future sales volume, operating revenues and expenses, per unit metrics and capital expenditures.

The annual inflation rate in the United States increased rapidly during 2022, and, although the inflation rate decreased through 2023, it still remains elevated compared to the rate of inflation over the prior five years. Inflationary pressures have multiple impacts on our business, including increasing our operating expenses and our cost of capital. While the prices for certain of the raw materials and services we use in our operations have generally decreased from the peak prices experienced during 2022, we will not fully realize the benefit of such reduced prices until we enter into new contracts for such materials and services, and inflationary pressures may cause prices to fluctuate. Additionally, certain of our commitments for demand charges under our existing long-term contracts and processing capacity are subject to consumer price index adjustments. Although we believe our scale and supply chain contracting strategy of using multi-year sand and frac crew contracts allows us to maximize capital and operating efficiencies, future increases in the inflation rate will negatively impact our long-term contracts with consumer price index adjustments.

While the prices for natural gas, NGLs and oil have historically been volatile, price volatility was especially pronounced during 2022, with natural gas prices peaking in August 2022, then steadily declining into the first half of 2023. The second half of 2023 saw moderate increases in natural gas prices; however, on average, prices in 2023 remained lower than in 2022. We expect commodity prices to be volatile throughout 2024 due to macroeconomic uncertainty and geopolitical tensions, including developments pertaining to Russia's invasion of Ukraine and conflicts in the Middle East. Our revenue, profitability, liquidity and financial position will continue to be impacted in the future by the market prices for natural gas and, to a lesser extent, NGLs and oil.

Additionally, after several years of delays, in the third quarter of 2023, Equitrans Midstream resumed forward construction of the Mountain Valley Pipeline following the approval of federal legislation ratifying and approving all permits and authorizations necessary for the construction and initial operation of the project. The fee structure and various conditions precedent specified in certain of our agreements with Equitrans Midstream, including but not limited to the Consolidated GGA, are tied to the date on which the Mountain Valley Pipeline is placed in service. As a result, the timing of the date on which the Mountain Valley Pipeline is ultimately placed in service, which is outside of our control, could impact our operating results during 2024, including our operating expenses and per unit metrics, average differential and any payments required to settle the Henry Hub Cash Bonus (defined and described in Note 3 to the Consolidated Financial Statements), if required.

Average Realized Price Reconciliation

The following table presents detailed natural gas and liquids operational information to assist in the understanding of our consolidated operations, including the calculation of our average realized price (\$/Mcf), which is based on adjusted operating revenues, a non-GAAP supplemental financial measure. Adjusted operating revenues is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Adjusted operating revenues should not be considered as an alternative to total operating revenues. See "Non-GAAP Financial Measures Reconciliation" for a reconciliation of adjusted operating revenues with total operating revenues, the most directly comparable financial measure calculated in accordance with GAAP.

Years Ended December 31,

2023 **2022**

(Thousands, unless otherwise noted)

NATURAL GAS

Sales volume (MMcf)		1,907,343		1,842,044
NYMEX price (\$/MMBtu)	\$	2.74	\$	6.64
Btu uplift		0.14		0.35
Natural gas price (\$/Mcf)	\$	2.88	\$	6.99
Basis (\$/Mcf) (a)	\$	(0.51)	\$	(0.77)
Cash settled basis swaps (\$/Mcf)		(0.03)		(0.02)
Average differential, including cash settled basis swaps (\$/Mcf)	\$	(0.54)	\$	(0.79)
Average adjusted price (\$/Mcf)	\$	2.34	\$	6.20
Cash settled derivatives (\$/Mcf)		0.34		(3.20)
Average natural gas price, including cash settled derivatives (\$/Mcf)	\$	2.68	\$	3.00
Natural gas sales, including cash settled derivatives	\$	5,112,278	\$	5,529,963

LIQUIDS

NGLs, excluding ethane:

Sales volume (MMcfe) (b)		64,859		56,735
Sales volume (Mbbbl)		10,810		9,456
NGLs price (\$/Bbl)	\$	36.39	\$	53.26
Cash settled derivatives (\$/Bbl)		(1.27)		(3.91)
Average NGLs price, including cash settled derivatives (\$/Bbl)	\$	35.12	\$	49.35
NGLs sales, including cash settled derivatives	\$	379,663	\$	466,664

Ethane:

Sales volume (MMcfe) (b)		34,441		35,100
Sales volume (Mbbbl)		5,740		5,850
Ethane price (\$/Bbl)	\$	6.00	\$	14.20
Ethane sales	\$	34,417	\$	83,096

Oil:

Sales volume (MMcfe) (b)		9,630		6,164
Sales volume (Mbbbl)		1,605		1,027
Oil price (\$/Bbl)	\$	59.93	\$	77.06
Oil sales	\$	96,191	\$	79,160

Total liquids sales volume (MMcfe) (b)		108,930		97,999
Total liquids sales volume (Mbbbl)		18,155		16,333
Total liquids sales	\$	510,271	\$	628,920

TOTAL

Total natural gas and liquids sales, including cash settled derivatives (c)	\$	5,622,549	\$	6,158,883
Total sales volume (MMcfe)		2,016,273		1,940,043
Average realized price (\$/Mcf)	\$	2.79	\$	3.17

- (a) Basis represents the difference between the ultimate sales price for natural gas, including the effects of delivered price benefit or deficit associated with our firm transportation agreements, and the NYMEX natural gas price.
- (b) NGLs, ethane and oil were converted to Mcfe at a rate of six Mcfe per barrel.
- (c) Total natural gas and liquids sales, including cash settled derivatives, is also referred to in this report as adjusted operating revenues, a non-GAAP supplemental financial measure.

Non-GAAP Financial Measures Reconciliation

The table below reconciles adjusted operating revenues, a non-GAAP supplemental financial measure, with total operating revenues, its most directly comparable financial measure calculated in accordance with GAAP. Adjusted operating revenues (also referred to in this report as total natural gas and liquids sales, including cash settled derivatives) is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Adjusted operating revenues excludes the revenue impacts of changes in the fair value of derivative instruments prior to settlement and net marketing services and other. We use adjusted operating revenues to evaluate earnings trends because, as a result of the measure's exclusion of the often-volatile changes in the fair value of derivative instruments prior to settlement, the measure reflects only the impact of settled derivative contracts. Net marketing services and other consists of the costs of, and recoveries on, pipeline capacity releases, revenues for gathering and processing services provided to third parties and other revenues. Because we consider net marketing services and other to be unrelated to our natural gas and liquids production activities, adjusted operating revenues excludes net marketing services and other. We believe that adjusted operating revenues provides useful information to investors for evaluating period-to-period comparisons of earnings trends.

	Years Ended December 31,	
	2023	2022
	(Thousands, unless otherwise noted)	
Total operating revenues	\$ 6,908,923	\$ 7,497,689
(Deduct) add:		
(Gain) loss on derivatives	(1,838,941)	4,642,932
Net cash settlements received (paid) on derivatives	900,650	(5,927,698)
Premiums paid for derivatives that settled during the period	(322,869)	(27,587)
Net marketing services and other	(25,214)	(26,453)
Adjusted operating revenues, a non-GAAP financial measure	<u>\$ 5,622,549</u>	<u>\$ 6,158,883</u>
Total sales volume (MMcfe)	2,016,273	1,940,043
Average realized price (\$/Mcf)	\$ 2.79	\$ 3.17

Sales Volume and Revenues

	Years Ended December 31,			
	2023	2022	Change	% Change
	(Thousands, unless otherwise noted)			
Sales volume (MMcfe)	2,016,273	1,940,043	76,230	3.9
Average daily sales volume (MMcfe/d)	5,524	5,315	209	3.9
Operating revenues:				
Sales of natural gas, NGLs and oil	\$ 5,044,768	\$ 12,114,168	\$ (7,069,400)	(58.4)
Gain (loss) on derivatives	1,838,941	(4,642,932)	6,481,873	(139.6)
Net marketing services and other	25,214	26,453	(1,239)	(4.7)
Total operating revenues	<u>\$ 6,908,923</u>	<u>\$ 7,497,689</u>	<u>\$ (588,766)</u>	<u>(7.9)</u>

Sales of natural gas, NGLs and oil. Sales of natural gas, NGLs and oil decreased for 2023 compared to 2022 due to lower average realized price, partly offset by increased sales volume.

Average realized price decreased for 2023 compared to 2022 due to lower NYMEX and liquids prices, partly offset by favorable cash settled derivatives and favorable differential. The following table presents the composition of net cash settlements that we received (paid) on derivatives.

	Years Ended December 31,	
	2023	2022
	(Thousands)	
Net cash settlements received (paid) on NYMEX natural gas hedge positions	\$ 976,432	\$ (5,855,959)
Net cash settlements paid on basis and liquids hedge positions	<u>(75,782)</u>	<u>(71,739)</u>
Net cash settlements received (paid) on derivatives	<u>\$ 900,650</u>	<u>\$ (5,927,698)</u>

Net cash settlements received (paid) on derivatives are included in average realized price but may not be included in operating revenues.

For 2023 and 2022, we paid premiums for derivatives that settled during the period of \$322.9 million and \$27.6 million, respectively.

Sales volume increased for 2023 compared to 2022 due to sales volume increases of 90 Bcfe from the assets acquired in the Tug Hill and XcL Midstream Acquisition, partly offset by sales volume decreases from the natural decline of producing wells and fewer wells turned-in-line during 2022 as a result of third-party supply chain constraints and delays in the development schedule of certain non-operated wells in which we have a working interest.

Gain (loss) on derivatives. For 2023, we recognized a gain on derivatives of \$1,838.9 million related primarily to increases in the fair market value of our NYMEX swaps and options due to decreases in NYMEX forward prices, partly offset by a loss on the derivative liability related to the Henry Hub Cash Bonus. For 2022, we recognized a loss on derivatives of \$4,642.9 million related primarily to decreases in the fair market value of our NYMEX swaps and options due to increases in NYMEX forward prices, partly offset by a gain on the derivative liability related to the Henry Hub Cash Bonus.

Operating Expenses

	Years Ended December 31,			
	2023	2022	Change	% Change
(Thousands, unless otherwise noted)				
Operating expenses:				
Gathering	\$ 1,282,402	\$ 1,316,213	\$ (33,811)	(2.6)
Transmission	642,688	601,497	41,191	6.8
Processing	232,170	199,266	32,904	16.5
Lease operating expenses (LOE)	158,973	156,523	2,450	1.6
Production taxes	95,727	144,462	(48,735)	(33.7)
Exploration	3,330	3,438	(108)	(3.1)
Selling, general and administrative	236,171	252,645	(16,474)	(6.5)
Production depletion	\$ 1,702,198	\$ 1,644,625	\$ 57,573	3.5
Other depreciation and depletion	29,944	21,337	8,607	40.3
Total depreciation and depletion	\$ 1,732,142	\$ 1,665,962	\$ 66,180	4.0
Per Unit (\$/Mcf):				
Gathering	\$ 0.64	\$ 0.68	\$ (0.04)	(5.9)
Transmission	0.32	0.31	0.01	3.2
Processing	0.12	0.10	0.02	20.0
LOE	0.08	0.08	—	—
Production taxes	0.05	0.07	(0.02)	(28.6)
Selling, general and administrative	0.12	0.13	(0.01)	(7.7)
Production depletion	0.84	0.85	(0.01)	(1.2)

Gathering. Gathering expense decreased on an absolute basis for 2023 compared to 2022 due primarily to lower gathering rates on certain contracts indexed to price. Gathering expense decreased on a per Mcfe basis for 2023 compared to 2022 due primarily to lower gathering rates on certain contracts indexed to price, which decreased in 2023, as well as the impact of the gathering assets acquired in the Tug Hill and XcL Midstream Acquisition, which are wholly owned by us and, therefore, reduce our gathering cost structure.

Transmission. Transmission expense increased on an absolute and per Mcfe basis for 2023 compared to 2022 due primarily to additional capacity acquired, partly offset by increased credits received from the Texas Eastern Transmission Pipeline.

Processing. Processing expense increased on an absolute and per Mcfe basis for 2023 compared to 2022 due primarily to processing expenses for the liquids-rich assets acquired in the Tug Hill and XcL Midstream Acquisition as well as inflation of third-party-contracted processing rates.

LOE. LOE increased on an absolute basis for 2023 compared to 2022 due primarily to increased LOE from the assets acquired in the Tug Hill and XcL Midstream Acquisition, partly offset by lower saltwater disposal costs and increased recycling. Saltwater disposal costs and recycle rates were favorably impacted by increased use of our internally developed produced water gathering and storage system, which was placed in service during the fourth quarter of 2022.

Production taxes. Production taxes decreased on an absolute and per Mcfe basis for 2023 compared to 2022 due to lower West Virginia severance taxes due to lower TETCO M2 price and lower Pennsylvania impact fees due to lower NYMEX price, partly offset by higher West Virginia property taxes due to assets acquired in the Tug Hill and XcL Midstream Acquisition and higher rates.

Selling, general and administrative. Selling, general and administrative expense decreased on an absolute and per Mcfe basis for 2023 compared to 2022 due primarily to lower long-term incentive compensation costs as a result of decreases in awards outstanding and changes in the fair value of awards. Long-term incentive compensation may fluctuate with changes in our stock price and performance conditions.

Depreciation and depletion. Production depletion expense increased on an absolute basis for 2023 compared to 2022 due to increased sales volume, partly offset by a lower annual depletion rate.

Loss (gain) on sale/exchange of long-lived assets. During 2023, we recognized a loss on sale/exchange of long-lived assets of \$17.4 million related to acreage trade agreements where the carrying value of the acres traded exceeded the fair value of the acres received.

Impairment of contract asset. During 2022, we recognized impairment of our contract asset of \$214.2 million. See Note 5 to the Consolidated Financial Statements.

Impairment and expiration of leases. During 2023 and 2022, we recognized impairment and expiration of leases of \$109.4 million and \$176.6 million, respectively, related primarily to leases that we no longer expect to extend or develop prior to their expiration based on our development plan.

Other operating expenses. Other operating expenses increased for 2023 compared to 2022 due primarily to transaction costs associated with the Tug Hill and XcL Midstream Acquisition, partly offset by decreased legal and environmental reserves, including from settlements. See Note 1 to the Consolidated Financial Statements for a summary of other operating expenses.

Other Income Statement Items

(Income) loss from investments. The change in (income) loss from investments was due primarily to a loss on our sale of our investment in Equitrans Midstream in 2022, partly offset by lower equity earnings recognized on our investment in LMM (defined in Note 1 to the Consolidated Financial Statements).

Dividend and other income. Dividend and other income decreased for 2023 compared to 2022 due primarily to lower dividends received on our investment in the Investment Fund (defined in Note 1 to the Consolidated Financial Statements) as well as dividends received on our investment in Equitrans Midstream in 2022.

Loss on debt extinguishment. During 2022, we recognized a loss on debt extinguishment of \$140.0 million due to our repayment and repurchase of debt, including our 3.00% notes due October 1, 2022.

Interest expense, net. Interest expense decreased for 2023 compared to 2022 due primarily to higher interest income earned on cash on hand and lower interest expense on lower revolving credit facility borrowings, partly offset by higher interest expense on debt as a result of the August 2023 draw down of the Term Loan Facility (defined and discussed in Note 8 to the Consolidated Financial Statements) and October 2022 senior notes issuances. The higher interest expense on debt was partly offset by our repayment and repurchase of debt disclosed in Note 8 to the Consolidated Financial Statements.

Income tax expense (benefit). See Note 7 to the Consolidated Financial Statements.

See "Critical Accounting Estimates" and Note 1 to the Consolidated Financial Statements for a discussion of our significant accounting policies and assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties. See also Item 1A., "Risk Factors – Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy may result in additional write-downs of the carrying amounts of our assets, including long-lived intangible assets, which could materially and adversely affect our results of operations in future periods."

Capital Resources and Liquidity

Although we cannot provide any assurance, we believe cash flows from operating activities and availability under our revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures and commitments for at least the next twelve months and, based on current expectations, for the long term.

Revolving Credit Facility

We primarily use borrowings under our revolving credit facility to fund working capital needs, timing differences between capital expenditures and other cash uses and cash flows from operating activities, margin deposit requirements on our derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts. See Note 8 to the Consolidated Financial Statements for further discussion of our revolving credit facility.

Known Contractual and Other Obligations; Planned Capital Expenditures

Purchase Obligations. We have commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines, some of which extend up to 20 years or longer. We have entered into agreements to release some of our capacity under these long-term contracts, subject to certain conditions that are currently unsatisfied. We also have commitments for processing capacity in order to extract heavier liquid hydrocarbons from the natural gas stream. In addition, we have commitments to pay for services and materials related to our operations, which primarily include minimum volume commitments to obtain water services and electric hydraulic fracturing services and commitments to purchase equipment, materials and sand. See Note 11 to the Consolidated Financial Statements for further discussion, including details regarding aggregate future payments for these items.

Contractual Commitments. We have contractual commitments under our debt agreements, including interest payments and principal repayments. See Note 8 to the Consolidated Financial Statements for further discussion of the contractual commitments under our debt agreements, including the timing of principal repayments.

Unrecognized Tax Benefits. As discussed further in Note 7 to the Consolidated Financial Statements, as of December 31, 2023, we had a total reserve for unrecognized tax benefits of \$8.5 million and an additional reserve of \$77.0 million that was offset against deferred tax assets for general business tax credit carryforwards and net operating losses (NOLs). We settled our consolidated U.S. federal income tax liability with the IRS through 2017 in January of 2023. We are currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities.

Planned Capital Expenditures and Sales Volume. In 2024, we expect to spend approximately \$2.15 billion to \$2.35 billion in total capital expenditures. We expect to fund our capital expenditures with cash generated from operations and, if required, borrowings under our revolving credit facility. Because we are the operator of a high percentage of our developed acreage, the amount and timing of certain of our capital expenditures is largely discretionary. We could choose to defer a portion of our planned 2024 capital expenditures depending on a variety of factors, including prevailing and anticipated prices for natural gas, NGLs and oil; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; and drilling, completion and acquisition costs. In 2024, we expect our sales volume to be 2,200 Bcfe to 2,300 Bcfe.

Operating Activities

Net cash provided by operating activities was \$3,179 million and \$3,466 million for 2023 and 2022, respectively. The decrease in 2023 compared to 2022 was due primarily to lower cash operating revenues, partly offset by net cash settlements received on derivatives in 2023 compared to net cash settlements paid on derivatives in 2022, favorable changes in working capital driven by declining accounts receivable and lower margin postings.

Our cash flows from operating activities are affected by movements in the market price for commodities. We are unable to predict such movements outside of the current market view as reflected in forward strip pricing. For a discussion of potential commodity market risks, refer to Item 1A., "Risk Factors – Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect on our revenue, profitability, future rate of growth, liquidity and financial position."

Investing Activities

Net cash used in investing activities was \$4,314 million and \$1,422 million for 2023 and 2022, respectively. The increase in 2023 compared to 2022 was attributable primarily to cash paid for the Tug Hill and XcL Midstream Acquisition in 2023 and increased capital expenditures.

The following table summarizes our capital expenditures.

	Years Ended December 31,	
	2023	2022
	(Millions)	
Reserve development (a)	\$ 1,587	\$ 1,131
Land and lease (b)	130	138
Other production infrastructure	63	82
Midstream	31	6
Capitalized overhead	60	51
Capitalized interest	41	28
Other	13	4
Total capital expenditures	<u>1,925</u>	<u>1,440</u>
Add (deduct): Non-cash items (c)	94	(40)
Total cash capital expenditures	<u>\$ 2,019</u>	<u>\$ 1,400</u>

- (a) Includes capital expenditures for water infrastructure of \$35.9 million and \$44.5 million for 2023 and 2022, respectively.
- (b) Capital expenditures attributable to noncontrolling interests were \$8.5 million and \$12.8 million for 2023 and 2022, respectively.
- (c) Represents the net impact of non-cash capital expenditures, including the effect of timing of receivables from working interest partners, accrued capital expenditures and capitalized share-based compensation costs. The impact of accrued capital expenditures includes the current period estimate, net of the reversal of the prior period accrual.

Financing Activities

Net cash used in financing activities was \$243 million and \$699 million for 2023 and 2022, respectively. For 2023, the primary uses of financing cash flows were repayment and retirement of debt, payment of dividends and repurchase and retirement of EQT Corporation common stock, and the primary source of financing cash flows was proceeds from the Term Loan Facility borrowings. For 2022, the primary uses of financing cash flows were repayment and retirement of debt, repurchase and retirement of EQT Corporation common stock and payment of dividends, and the primary source of financing cash flows was proceeds from the issuance of debt.

See Note 8 to the Consolidated Financial Statements for further discussion of our debt and borrowings under our revolving credit facility and the Term Loan Facility, including discussion of events that occurred subsequent to December 31, 2023.

On February 8, 2024, our Board of Directors declared a quarterly cash dividend of \$0.1575 per share of EQT Corporation common stock, payable on March 1, 2024, to shareholders of record at the close of business on February 20, 2024.

Depending on our actual and anticipated sources and uses of liquidity, prevailing market conditions and other factors, we may from time to time seek to redeem or repurchase our outstanding debt or equity securities through tender offers or other cash purchases in the open market or privately negotiated transactions. The amounts involved in any such transactions may be material. See Note 8 to the Consolidated Financial Statements for discussion of redemptions and repurchases of debt and Note 9 to the Consolidated Financial Statements for discussion of repurchases of EQT Corporation common stock.

Security Ratings and Financing Triggers

The table below reflects the credit ratings and rating outlooks assigned to our debt instruments as of December 31, 2023. Our credit ratings and rating outlooks are subject to revision or withdrawal at any time by the assigning rating agency, and each rating should be evaluated independent from any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a rating agency if, in the rating agency's judgment, circumstances so warrant. See Note 3 to the Consolidated Financial Statements for a description of what is deemed investment grade.

Rating agency	Senior notes	Outlook
Moody's Investors Service (Moody's)	Baa3	Stable
Standard & Poor's Ratings Service (S&P)	BBB–	Stable
Fitch Ratings Service (Fitch)	BBB–	Stable

Changes in credit ratings may affect our access to the capital markets, the cost of short-term debt through interest rates and fees under our revolving credit facility, the interest rate on the Term Loan Facility and senior notes with adjustable rates, the rates available on new long-term debt, our pool of investors and funding sources, the borrowing costs and margin deposit requirements on our OTC derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts. Margin deposits on our OTC derivative instruments are also subject to factors other than credit rating, such as natural gas prices and credit thresholds set forth in the agreements between us and our hedging counterparties.

Our debt agreements and other financial obligations contain various provisions that, if not complied with, could result in default or event of default under our revolving credit facility and the Term Loan Facility, mandatory partial or full repayment of amounts outstanding, reduced loan capacity or other similar actions. The most significant covenants and events of default under our debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. Our revolving credit facility and the Term Loan Facility contain financial covenants that require us to have a total debt-to-total capitalization ratio no greater than 65%. As of December 31, 2023, we were in compliance with all debt provisions and covenants under our debt agreements.

See Note 8 to the Consolidated Financial Statements for a discussion of borrowings under our revolving credit facility and the Term Loan Facility.

Commodity Risk Management

The substantial majority of our commodity risk management program is related to hedging sales of our produced natural gas. The overall objective of our hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices. The derivative commodity instruments that we use are primarily swap, collar and option agreements. The following table summarizes the approximate volume and prices of our NYMEX hedge positions as of February 9, 2024. The difference between the fixed price and NYMEX price is included in average differential presented in our price reconciliation in "Average Realized Price Reconciliation." The fixed price natural gas sales agreements can be physically or financially settled.

	Q1 2024(a)	Q2 2024	Q3 2024	Q4 2024
Hedged Volume (MMDth)	283	260	237	127
Hedged Volume (MMDth/d)	3.1	2.9	2.6	1.4
Swaps – Short				
Volume (MMDth)	136	215	192	95
Avg. Price (\$/Dth)	\$ 3.52	\$ 3.26	\$ 3.27	\$ 3.26
Calls – Long				
Volume (MMDth)	13	13	13	13
Avg. Strike (\$/Dth)	\$ 3.20	\$ 3.20	\$ 3.20	\$ 3.20
Calls – Short				
Volume (MMDth)	162	61	62	46
Avg. Strike (\$/Dth)	\$ 6.16	\$ 4.22	\$ 4.22	\$ 4.27
Puts – Long				
Volume (MMDth)	147	45	45	32
Avg. Strike (\$/Dth)	\$ 4.20	\$ 4.05	\$ 4.05	\$ 4.10
Option Premiums				
Cash Settlement of Deferred Premiums (millions)	\$ (34)	\$ (4)	\$ (4)	\$ —

(a) January 1 through March 31.

We have also entered into derivative instruments to hedge basis. We may use other contractual agreements to implement our commodity hedging strategy from time to time.

See Item 7A., "Quantitative and Qualitative Disclosures About Market Risk" and Note 3 to the Consolidated Financial Statements for further discussion of our hedging program.

Off-Balance Sheet Arrangements

As of December 31, 2023, we did not have any material off-balance sheet arrangements other than the commitments described in Note 11 to the Consolidated Financial Statements.

Commitments and Contingencies

See Note 11 to the Consolidated Financial Statements for a discussion of our commitments and contingencies.

Recently Issued Accounting Standards

Our recently issued accounting standards are described in Note 1 to the Consolidated Financial Statements.

Critical Accounting Estimates

Our significant accounting policies are described in Note 1 to the Consolidated Financial Statements. Management's discussion and analysis of the Consolidated Financial Statements and results of operations are based on our Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of the Consolidated Financial Statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The following critical accounting estimates, which were reviewed by the Audit Committee of our Board of Directors (the Audit Committee), relate to our more significant judgments and estimates used in the preparation of our Consolidated Financial Statements. Actual results could differ from our estimates.

Accounting for Gas, NGLs and Oil Producing Activities. We use the successful efforts method of accounting for our oil and gas producing activities. See Note 1 to the Consolidated Financial Statements for a discussion of the fair value measurement and any subsequent impairments of our proved and unproved oil and gas properties and other long-lived assets as well as evaluation of the recoverability of capitalized costs of unproved oil and gas properties.

We believe accounting for natural gas, NGLs and oil producing activities is a "critical accounting estimate" because the evaluations of impairment of proved properties involve significant judgment about future events, such as future sales prices of natural gas and NGLs and future production costs, as well as the amount of natural gas and NGLs recorded and timing of recoveries. Significant changes in these estimates could result in the costs of our proved and unproved properties not being recoverable; therefore, we would be required to recognize impairment. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

See Note 1 to the Consolidated Financial Statements for additional information on impairments of our proved and unproved oil and gas properties. See also Item 1A., "Risk Factors – Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy may result in additional write-downs of the carrying amounts of our assets, including long-lived intangible assets, which could materially and adversely affect our results of operations in future periods."

Oil and Gas Reserves. Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods and government regulations 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.

Our estimates of proved reserves are reassessed annually using geological, reservoir and production performance data. Reserve estimates are prepared by our engineers and audited by independent engineers. Revisions may result from changes in, among other things, reservoir performance, development plans, prices, operating costs, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in certain proved reserves due to reaching economic limits sooner. A material change in the estimated volume of reserves could have an impact on the depletion rate calculation and our Consolidated Financial Statements.

We estimate future net cash flows from natural gas, NGLs and oil reserves based on selling prices and costs using a twelve-month average price, which is calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the twelve-month period and, as such, is subject to change in subsequent periods. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Income tax expense is based on currently enacted statutory tax rates and tax deductions and credits available under current laws.

We believe oil and gas reserves is a "critical accounting estimate" because we must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the timing of development expenditures. Future results of operations and the strength of our Consolidated Balance Sheet for any quarterly or annual period could be materially affected by changes in our assumptions. Based on proved reserves as of December 31, 2023, we estimate that a 1% change in proved reserves would decrease or increase 2024 depletion expense by approximately \$15 million and \$27 million, respectively, based on current production estimates for 2024.

See also Item 1A., "Risk Factors – Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect on our revenue, profitability, future rate of growth, liquidity and financial position."

Income Taxes. We recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been included in our Consolidated Financial Statements or tax returns. See Note 1 to the Consolidated Financial Statements for a discussion of significant accounting policies related to income taxes and Note 7 to the Consolidated Financial Statements for a discussion of deferred tax assets, valuation allowances and the amount of financial statement benefit recorded for uncertain tax positions.

We believe income taxes are "critical accounting estimates" because we must assess the likelihood that our deferred tax assets will be recovered from future taxable income and exercise judgment on the amount of financial statement benefit recorded for uncertain tax positions. To the extent that a valuation allowance or uncertain tax position is established or increased or decreased during a period, we record an expense or benefit in income tax expense in our Statements of Consolidated Operations. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. A change to future taxable income or tax planning strategies could impact our ability to utilize deferred tax assets, which would increase or decrease our income tax expense and taxes paid. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

Derivative Instruments. We enter into derivative commodity instrument contracts primarily to reduce exposure to commodity price risk associated with future sales of our natural gas production. See Note 4 to the Consolidated Financial Statements for a description of the fair value hierarchy. The values reported in the Consolidated Financial Statements change as these estimates are revised to reflect actual results or as market conditions or other factors, many of which are beyond our control, change.

We believe derivative instruments are "critical accounting estimates" because our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments due to the volatility of both NYMEX natural gas prices and basis. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. Refer to Item 7A., "Quantitative and Qualitative Disclosures about Market Risk" for discussion of a hypothetical increase or decrease of 10% in the market price of natural gas.

Business Combinations. Accounting for a business combination requires a company to record the identifiable assets and liabilities acquired at fair value. In the third quarter of 2023, we completed the Tug Hill and XcL Midstream Acquisition, and in the third quarter of 2021, we completed the Alta Acquisition (defined and discussed in Note 6 to the Consolidated Financial Statements). See Note 6 to the Consolidated Financial Statements for a discussion of the most significant assumptions used to estimate the fair value of the assets acquired and liabilities assumed.

We believe business combinations are "critical accounting estimates" because the valuation of acquired assets and assumed liabilities involves significant judgment about future events. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

Contingencies and Asset Retirement Obligations. We are involved in various legal and regulatory proceedings that arise in the ordinary course of business. We record a liability for contingencies based on our assessment that a loss is probable and the amount of the loss can be reasonably estimated. We consider many factors in making these assessments, including historical experience and matter specifics. Estimates are developed in consultation with legal counsel and are based on an analysis of potential results. See Note 11 to the Consolidated Financial Statements.

We accrue a liability for asset retirement obligations based on an estimate of the amount and timing of settlement. For oil and gas wells, the fair value of our plugging and abandonment obligations is recorded at the time the obligation is incurred, which is typically at the time the well is spud. See Note 1 to the Consolidated Financial Statements.

We believe contingencies and asset retirement obligations are "critical accounting estimates" because we must assess the probability of loss related to contingencies and the expected amount and timing of asset retirement obligation settlement. In addition, we must determine the estimated present value of future liabilities. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. If we incur losses related to contingencies that are higher than we expect, we could incur additional costs to settle such obligations. If the expected amount and timing of our asset retirement obligations change, we will be required to adjust the carrying value of our liabilities in future periods. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk and Derivative Instruments. Our primary market risk exposure is the volatility of future prices for natural gas and NGLs. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas and NGLs at our ultimate sales points and, thus, cannot predict the ultimate impact of prices on our operations. Prolonged low, or significant, extended declines in, natural gas and NGLs prices could adversely affect, among other things, our development plans, which would decrease the pace of development and the level of our proved reserves. Increases in natural gas and NGLs prices may be accompanied by, or result in, increased well drilling costs, increased production taxes, increased LOE, increased volatility in seasonal gas price spreads for our storage assets and increased end-user conservation or conversion to alternative fuels. In addition, to the extent we have hedged our production at prices below the current market price, we will not benefit fully from an increase in the price of natural gas, and, depending on our then-current credit ratings and the terms of our hedging contracts, we may be required to post additional margin with our hedging counterparties.

The overall objective of our hedging program is to protect our cash flows from undue exposure to the risk of changing commodity prices. Our use of derivatives is further described in Note 3 to the Consolidated Financial Statements and "Commodity Risk Management" under "Capital Resources and Liquidity" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations." Our OTC derivative commodity instruments are placed primarily with financial institutions and the creditworthiness of those institutions is regularly monitored. We primarily enter into derivative instruments to hedge forecasted sales of production. We also enter into derivative instruments to hedge basis. Our use of derivative instruments is implemented under a set of policies approved by our management-level Hedge and Financial Risk Committee and is reviewed by our Board of Directors.

For derivative commodity instruments used to hedge our forecasted sales of production, which are at, for the most part, NYMEX natural gas prices, we set policy limits relative to the expected production and sales levels that are exposed to price risk. We have an insignificant amount of financial natural gas derivative commodity instruments for trading purposes.

The derivative commodity instruments we use are primarily swap, collar and option agreements. These agreements may require payments to, or receipt of payments from, counterparties based on the differential between two prices for the commodity. We use these agreements to hedge our NYMEX and basis exposure. We may also use other contractual agreements when executing our commodity hedging strategy.

We monitor price and production levels on a continuous basis and adjust quantities hedged as warranted.

A hypothetical decrease of 10% in the NYMEX natural gas price on December 31, 2023 and 2022 would increase the fair value of our natural gas derivative commodity instruments by approximately \$204 million and \$727 million, respectively. A hypothetical increase of 10% in the NYMEX natural gas price on December 31, 2023 and 2022 would decrease the fair value of our natural gas derivative commodity instruments by approximately \$482 million and \$333 million, respectively. For purposes of this analysis, we applied the 10% change in the NYMEX natural gas price on December 31, 2023 and 2022 to our natural gas derivative commodity instruments as of December 31, 2023 and 2022 to calculate the hypothetical change in fair value. The change in fair value was determined using a method similar to our normal process for determining derivative commodity instrument fair value described in Note 4 to the Consolidated Financial Statements.

The above analysis of our derivative commodity instruments does not include the offsetting impact that the same hypothetical price movement may have on our physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge our forecasted produced natural gas approximates a portion of our expected physical sales of natural gas; therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments held to hedge our forecasted production associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on our physical sales of natural gas, assuming that the derivative commodity instruments are not closed in advance of their expected term and the derivative commodity instruments continue to function effectively as hedges of the underlying risk.

If the underlying physical transactions or positions are liquidated prior to the maturity of the derivative commodity instruments, a loss on the financial instruments may occur or the derivative commodity instruments might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first.

Interest Rate Risk. Changes in market interest rates affect the amount of interest we earn on cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility and the Term Loan Facility. None of the interest we pay on our senior notes fluctuates based on changes to market interest rates. A 1% increase in interest rates for the borrowings under our revolving credit facility and the Term Loan Facility during 2023 would have increased interest expense by approximately \$12.9 million.

Interest rates for our revolving credit facility, the Term Loan Facility, our 6.125% senior notes due 2025 and our 7.000% senior notes due 2030 fluctuate based on changes to the credit ratings assigned to our senior notes by Moody's, S&P and Fitch. Interest rates for our other outstanding senior notes do not fluctuate based on changes to the credit ratings assigned to our senior notes by Moody's, S&P and Fitch. For a discussion of credit rating downgrade risk, see Item 1A., "Risk Factors – Our operations have substantial capital requirements, and we may not be able to obtain needed capital or financing on satisfactory terms." Changes in interest rates affect the fair value of our fixed rate debt. See Note 8 to the Consolidated Financial Statements for further discussion of our debt and Note 4 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value measurement of our debt.

Other Market Risks. We are exposed to credit loss in the event of nonperformance by counterparties to our derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. Our OTC derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as the financial industry as a whole. We use various processes and analyses to monitor and evaluate our credit risk exposures, including monitoring current market conditions and counterparty credit fundamentals. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, we enter into transactions primarily with financial counterparties that are of investment grade, enter into netting agreements whenever possible and may obtain collateral or other security.

Approximately 86%, or \$912 million, of our OTC derivative contracts outstanding at December 31, 2023 had a positive fair value. Approximately 36%, or \$710 million, of our OTC derivative contracts outstanding at December 31, 2022 had a positive fair value.

As of December 31, 2023, we were not in default under any derivative contracts and had no knowledge of default by any counterparty to our derivative contracts. During 2023, we made no adjustments to the fair value of our derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in our established fair value procedure. We monitor market conditions that may impact the fair value of our derivative contracts.

We are exposed to the risk of nonperformance by credit customers on physical sales of natural gas, NGLs and oil. Revenues and related accounts receivable from our operations are generated primarily from the sale of our produced natural gas, NGLs and oil to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through our transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States and Canada. We also contract with certain processors to market a portion of our NGLs on our behalf.

No one lender of the large group of financial institutions in the syndicate for our revolving credit facility and the Term Loan Facility holds more than 10% of the financial commitments under either facility. The large syndicate group and relatively low percentage of participation by each lender are expected to limit our exposure to disruption or consolidation in the banking industry.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EQT Corporation and subsidiaries (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income (loss), cash flows and equity for each of the three years in the period ended December 31, 2023, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 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 U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 14, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, depletion and amortization ('DD&A') of proved oil and natural gas properties

Description of the Matter At December 31, 2023, the net book value of the Company's proved oil and natural gas properties was \$19,737 million, and depreciation, depletion and amortization (DD&A) expense was \$1,732 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, DD&A is recorded on a cost center basis using the units-of-production method. Proved developed reserves, as estimated by the Company's internal engineers, are used to calculate depreciation of wells and related equipment and facilities and amortization of intangible drilling costs. Total proved reserves, also estimated by the Company's engineers, are used to calculate depletion on property acquisitions. Proved natural gas, natural gas liquids (NGLs) and oil reserve estimates are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes generally financial and non-financial inputs. Significant judgment is required by the Company's engineers in interpreting the data when estimating proved natural gas, NGLs and oil reserves. Estimating reserves also requires the selection of inputs, including natural gas, NGLs and oil price assumptions, and future operating and capital costs assumptions, among others. Because of the complexity involved in estimating natural gas, NGLs and oil reserves, management used independent engineers to audit the estimates prepared by the Company's internal engineers as of December 31, 2023.

Auditing the Company's DD&A calculation is especially complex because of the use of the work of the internal engineers and the independent engineers and the evaluation of management's determination of the inputs described above used by the specialists in estimating proved natural gas, NGLs and oil reserves.

How We Addressed the Matter in Our Audit We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the specialists for use in estimating the proved natural gas, NGLs and oil reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff and the independent engineers used to audit the estimates. In addition, we evaluated the completeness and accuracy of the financial data and inputs described above used by the specialists in estimating proved natural gas, NGLs and oil reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan and the availability of capital relative to the drill plan. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved natural gas, NGLs, and oil reserves amounts used in the Company's reserve report.

Valuation of Acquired Natural Gas and Oil Properties

Description of the Matter As described in Note 6 to the consolidated financial statements, on August 22, 2023, the Company completed the acquisition of THQ Appalachia I, LLC and THQ-XcL Holdings I, LLC and subsidiaries. The Company's accounting for the acquisition included determining the fair value of the acquired natural gas and oil properties. The determination of fair value of the acquired natural gas and oil properties included significant judgment and assumptions by management, including future commodity prices, anticipated production volumes, future operating and development costs, and a weighted average cost of capital (WACC).

Auditing the Company's valuation of acquired natural gas and oil properties involved a high degree of subjectivity as the determination of fair value was based on assumptions as described above about future market and economic conditions. In addition, certain of the assumptions developed by the Company's internal engineers in conjunction with the reserve estimates described in the preceding critical audit matter are used as inputs in the cash flow model.

How We Addressed the Matter in Our Audit We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Company's process to estimate fair value for the acquired natural gas and oil properties. For example, we tested controls over management's assessment of the appropriateness of the significant assumptions that are inputs to the fair value calculation and management's review of the valuation model.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff, the independent engineers used to audit the estimates, and the external valuation specialist used to assist with the determination of the fair value of certain acquired assets. Our testing of the Company's estimate of fair value of the acquired natural gas and oil properties included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. The audit effort involved the use of our valuation specialists to assist in evaluating the appropriateness of the methodology used in the cash flow model, as well as testing the significant market-related assumptions described above used to develop the fair value estimate. We evaluated the reasonableness of management's assumptions by comparing the key market-related assumptions (including future natural gas prices and WACC rates) used in the cash flow model to external market and third-party data and anticipated production volumes to the reserve estimates audited by the independent engineers.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1950.

Pittsburgh, Pennsylvania

February 14, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on Internal Control Over Financial Reporting

We have audited EQT Corporation and subsidiaries' internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, EQT Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income (loss), cash flows and equity for each of the three years in the period ended December 31, 2023 and the related notes and the financial statement schedule listed in the Index at Item 15(a), and our report dated February 14, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania

February 14, 2024

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED OPERATIONS
YEARS ENDED DECEMBER 31,

	<u>2023</u>	<u>2022</u>	<u>2021</u>
	(Thousands, except per share amounts)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	\$ 5,044,768	\$ 12,114,168	\$ 6,804,020
Gain (loss) on derivatives	1,838,941	(4,642,932)	(3,775,042)
Net marketing services and other	25,214	26,453	35,685
Total operating revenues	<u>6,908,923</u>	<u>7,497,689</u>	<u>3,064,663</u>
Operating expenses:			
Transportation and processing	2,157,260	2,116,976	1,942,165
Production	254,700	300,985	225,279
Exploration	3,330	3,438	24,403
Selling, general and administrative	236,171	252,645	196,315
Depreciation and depletion	1,732,142	1,665,962	1,676,702
Loss (gain) on sale/exchange of long-lived assets	17,445	(8,446)	(21,124)
Impairment of contract asset	—	214,195	—
Impairment and expiration of leases	109,421	176,606	311,835
Other operating expenses	84,043	57,331	70,063
Total operating expenses	<u>4,594,512</u>	<u>4,779,692</u>	<u>4,425,638</u>
Operating income (loss)	2,314,411	2,717,997	(1,360,975)
(Income) loss from investments	(7,596)	4,931	(71,841)
Dividend and other income	(1,231)	(11,280)	(19,105)
Loss on debt extinguishment	80	140,029	9,756
Interest expense, net	219,660	249,655	289,753
Income (loss) before income taxes	2,103,498	2,334,662	(1,569,538)
Income tax expense (benefit)	368,954	553,720	(428,037)
Net income (loss)	1,734,544	1,780,942	(1,141,501)
Less: Net (loss) income attributable to noncontrolling interests	(688)	9,977	1,246
Net income (loss) attributable to EQT Corporation	<u>\$ 1,735,232</u>	<u>\$ 1,770,965</u>	<u>\$ (1,142,747)</u>
Income (loss) per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	380,902	370,048	323,196
Net income (loss) attributable to EQT Corporation	<u>\$ 4.56</u>	<u>\$ 4.79</u>	<u>\$ (3.54)</u>
Diluted (Note 1):			
Weighted average common stock outstanding	413,224	406,495	323,196
Net income (loss) attributable to EQT Corporation	<u>\$ 4.22</u>	<u>\$ 4.38</u>	<u>\$ (3.54)</u>

The accompanying notes are an integral part of these Consolidated Financial Statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
YEARS ENDED DECEMBER 31,

	2023	2022	2021
	(Thousands)		
Net income (loss)	\$ 1,734,544	\$ 1,780,942	\$ (1,141,501)
Other comprehensive income, net of tax:			
Other postretirement benefits liability adjustment, net of tax: \$59, \$488 and \$254	310	1,617	744
Comprehensive income (loss)	1,734,854	1,782,559	(1,140,757)
Less: Comprehensive (loss) income attributable to noncontrolling interests	(688)	9,977	1,246
Comprehensive income (loss) attributable to EQT Corporation	\$ 1,735,542	\$ 1,772,582	\$ (1,142,003)

The accompanying notes are an integral part of these Consolidated Financial Statements.

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	<u>2023</u>	<u>2022</u>
	<u>(Thousands)</u>	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 80,977	\$ 1,458,644
Accounts receivable (less provision for doubtful accounts: \$663 and \$605)	823,695	1,608,089
Derivative instruments, at fair value	978,634	812,371
Income tax receivable	91,414	—
Prepaid expenses and other	38,255	135,337
Total current assets	<u>2,012,975</u>	<u>4,014,441</u>
Property, plant and equipment	33,817,169	27,393,919
Less: Accumulated depreciation and depletion	10,866,999	9,226,586
Net property, plant and equipment	<u>22,950,170</u>	<u>18,167,333</u>
Other assets	321,953	488,152
Total assets	<u>\$ 25,285,098</u>	<u>\$ 22,669,926</u>
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt	\$ 292,432	\$ 422,632
Accounts payable	1,272,522	1,574,610
Derivative instruments, at fair value	186,363	1,393,487
Other current liabilities	285,523	341,491
Total current liabilities	<u>2,036,840</u>	<u>3,732,220</u>
Term Loan Facility borrowings	1,244,265	—
Senior notes	4,176,180	5,167,849
Note payable to EQM Midstream Partners, LP	82,236	88,484
Deferred income taxes	1,904,821	1,442,406
Other liabilities and credits	1,059,939	1,025,639
Total liabilities	<u>10,504,281</u>	<u>11,456,598</u>
Equity:		
Common stock, no par value, shares authorized: 640,000, shares issued: 419,896 and 365,363	12,093,986	9,891,890
Retained earnings	2,681,898	1,283,578
Accumulated other comprehensive loss	(2,684)	(2,994)
Total common shareholders' equity	<u>14,773,200</u>	<u>11,172,474</u>
Noncontrolling interest in consolidated subsidiaries	7,617	40,854
Total equity	<u>14,780,817</u>	<u>11,213,328</u>
Total liabilities and equity	<u>\$ 25,285,098</u>	<u>\$ 22,669,926</u>

The accompanying notes are an integral part of these Consolidated Financial Statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
YEARS ENDED DECEMBER 31,

	2023	2022	2021
	(Thousands)		
Cash flows from operating activities:			
Net income (loss)	\$ 1,734,544	\$ 1,780,942	\$ (1,141,501)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax expense (benefit)	384,666	534,612	(427,470)
Depreciation and depletion	1,732,142	1,665,962	1,676,702
Impairments and loss/gain on sale/exchange of long-lived assets	126,866	382,355	290,711
(Income) loss from investments	(7,596)	4,931	(71,841)
Loss on debt extinguishment	80	140,029	9,756
Share-based compensation expense	49,834	45,201	28,169
Distribution of earnings from equity method investment	18,693	50,220	14,911
Amortization, accretion and other	16,943	32,645	32,175
(Gain) loss on derivatives	(1,838,941)	4,642,932	3,775,042
Net cash settlements received (paid) on derivatives	900,650	(5,927,698)	(2,091,003)
Net premiums (paid) received on derivative instruments	(322,663)	14,200	(66,495)
Changes in other assets and liabilities:			
Accounts receivable	867,679	(168,978)	(699,992)
Accounts payable	(406,113)	181,459	456,988
Other current assets	93,787	48,576	(75,100)
Other items, net	(171,721)	38,172	(48,604)
Net cash provided by operating activities	3,178,850	3,465,560	1,662,448
Cash flows from investing activities:			
Capital expenditures	(2,019,037)	(1,400,443)	(1,055,128)
Cash paid for acquisitions, net of cash acquired (Note 6)	(2,271,881)	(205,347)	(1,030,239)
Proceeds from sale/exchange of assets	4,200	8,572	2,452
Proceeds from sale of investment shares	—	189,249	24,369
Other investing activities	(26,937)	(13,784)	(14,196)
Net cash used in investing activities	(4,313,655)	(1,421,753)	(2,072,742)
Cash flows from financing activities:			
Proceeds from revolving credit facility borrowings	1,007,000	10,242,000	8,086,000
Repayment of revolving credit facility borrowings	(1,007,000)	(10,242,000)	(8,386,000)
Proceeds from issuance of debt	1,250,000	1,000,000	1,000,000
Debt issuance costs	(5,336)	(26,506)	(19,713)
Repayment and retirement of debt	(1,015,836)	(917,039)	(154,336)
Discounts received (premiums paid) on debt extinguishment	5,178	(135,308)	(9,599)
Dividends paid	(228,339)	(203,629)	—
Repurchase and retirement of common stock	(201,029)	(409,485)	(12,922)
Net (distribution to) contribution from noncontrolling interest	(7,322)	3,408	7,500
Other financing activities	(40,178)	(10,567)	(4,883)
Net cash (used in) provided by financing activities	(242,862)	(699,126)	506,047
Net change in cash and cash equivalents	(1,377,667)	1,344,681	95,753
Cash and cash equivalents at beginning of year	1,458,644	113,963	18,210
Cash and cash equivalents at end of year	\$ 80,977	\$ 1,458,644	\$ 113,963

The accompanying notes are an integral part of these Consolidated Financial Statements.
See Note 1 for supplemental cash flow information.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2023, 2022 and 2021

	Common Stock		Treasury Stock	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss (a)	Noncontrolling Interest in Consolidated Subsidiaries	Total Equity
	Shares	No Par Value					
(Thousands, except per share amounts)							
Balance at December 31, 2020	278,345	\$ 8,145,539	\$ (29,348)	\$ 1,056,626	\$ (5,355)	\$ 7,490	\$ 9,174,952
Comprehensive loss, net of tax:							
Net (loss) income				(1,142,747)		1,246	(1,141,501)
Other postretirement benefits liability adjustment, net of tax: \$254					744		744
Share-based compensation plans	627	21,982	11,302				33,284
Repurchase and retirement of common stock	(1,362)	(21,106)		(8,279)			(29,385)
Alta Acquisition	98,789	1,925,405					1,925,405
Contribution from noncontrolling interest						7,500	7,500
Balance at December 31, 2021	376,399	10,071,820	(18,046)	(94,400)	(4,611)	16,236	9,970,999
Comprehensive income, net of tax:							
Net income				1,770,965		9,977	1,780,942
Other postretirement benefits liability adjustment, net of tax: \$488					1,617		1,617
Dividends (\$0.55 per share)				(203,629)			(203,629)
Share-based compensation plans	2,100	23,671	18,046				41,717
Convertible Notes settlements	4	63					63
Repurchase and retirement of common stock	(13,140)	(203,664)		(189,358)			(393,022)
Distribution to noncontrolling interest						(11,592)	(11,592)
Contribution from noncontrolling interest						15,000	15,000
Other						11,233	11,233
Balance at December 31, 2022	365,363	9,891,890	—	1,283,578	(2,994)	40,854	11,213,328
Comprehensive income, net of tax:							
Net income (loss)				1,735,232		(688)	1,734,544
Other postretirement benefits liability adjustment, net of tax: \$59					310		310
Dividends (\$0.61 per share)				(228,339)			(228,339)
Share-based compensation plans	2,274	18,180					18,180
Convertible Notes settlements	8,565	122,830					122,830
Repurchase and retirement of common stock	(5,906)	(91,545)		(109,484)			(201,029)
Tug Hill and XcL Midstream Acquisition	49,600	2,152,631					2,152,631
Distribution to noncontrolling interest						(11,072)	(11,072)
Contribution from noncontrolling interest						3,750	3,750
Dissolution of consolidated variable interest entity						(25,227)	(25,227)
Other				911			911
Balance at December 31, 2023	<u>419,896</u>	<u>\$12,093,986</u>	<u>\$ —</u>	<u>\$ 2,681,898</u>	<u>\$ (2,684)</u>	<u>\$ 7,617</u>	<u>\$ 14,780,817</u>

Common shares authorized (in thousands): 640,000. Preferred shares authorized (in thousands): 3,000. There were no preferred shares issued or outstanding.

- (a) Amounts included in accumulated other comprehensive loss are related to other postretirement benefits liability adjustments, net of tax, which are attributable to net actuarial losses and net prior service costs.

The accompanying notes are an integral part of these Consolidated Financial Statements.

EQT CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2023

1. Summary of Significant Accounting Policies

Nature of Operations. EQT Corporation is a natural gas production company with operations focused in the Appalachian Basin.

Principles of Consolidation. The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which EQT Corporation directly or indirectly holds a controlling interest (collectively, the Company). Intercompany accounts and transactions have been eliminated in consolidation.

Management evaluates whether an entity is a variable interest entity and whether the Company is the primary beneficiary of that entity or interest; consolidation is required if both criteria are met. The Company records noncontrolling interest in its Consolidated Financial Statements for any non-wholly-owned consolidated subsidiary. See "Equity Method Investments" and "Investments in Equity Securities" for accounting policies for the Company's investments in entities that it does not consolidate.

In 2020, the Company entered into a partnership (the Partnership) with a third-party investor (the Investor) to purchase certain mineral rights in the Appalachian Basin. During 2023, the Partnership's assets were distributed pro rata to the Company and the Investor, and the Partnership was dissolved. Prior to the Partnership's dissolution, the Company consolidated the Partnership as management had determined that the Partnership was a variable interest entity, and the Company was the primary beneficiary of the Partnership.

Certain of the Company's midstream gathering systems are not wholly owned but are operated by the Company pursuant to a construction, ownership and operation agreement. The Company records the pro rata share of revenues, expenses, assets and liabilities that it is entitled under such agreement in the Company's financial statements.

Segments. The Company's operations consist of one reportable segment. The Company has a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. The Company measures financial performance as a single enterprise and not on an area-by-area basis. Substantially all of the Company's operating revenues, income from operations and assets are generated and located in the United States.

Reclassification. Certain previously reported amounts have been reclassified to conform to the current year presentation.

Use of Estimates. The preparation of financial statements in conformity with United States generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the amounts reported herein. Actual results could differ from those estimates.

Cash and Cash Equivalents. The Company considers all highly-liquid investments with an original maturity of three months or less when purchased to be cash equivalents and accounts for such investments at cost. Interest earned on cash equivalents is included as a reduction of interest expense, net.

Accounts Receivable. The Company's accounts receivable relates primarily to the sales of natural gas, natural gas liquids (NGLs) and oil and amounts due from joint interest partners. See Note 2 for a discussion of amounts due from contracts with customers.

Derivative Instruments. See Note 3 for a discussion of the Company's derivative instruments and Note 4 for a description of the fair value hierarchy and a discussion of the Company's fair value measurements.

Property, Plant and Equipment. The following table summarizes the Company's property, plant and equipment.

	December 31,	
	2023	2022
	(Thousands)	
Oil and gas producing properties	\$ 32,510,595	\$ 26,890,562
Less: Accumulated depreciation and depletion	10,734,099	9,119,553
Net oil and gas producing properties	21,776,496	17,771,009
Other properties, at cost less accumulated depreciation	1,173,674	396,324
Net property, plant and equipment	<u>\$ 22,950,170</u>	<u>\$ 18,167,333</u>

The Company uses the successful efforts method of accounting for gas, NGLs and oil producing activities. Under this method, the cost of productive wells and related equipment, development dry holes and productive acreage, including productive mineral interests, are capitalized and depleted using the unit-of-production method. These costs include salaries, benefits and other internal costs directly attributable to production activities. The Company capitalized internal costs of approximately \$60 million, \$51 million and \$58 million in 2023, 2022 and 2021, respectively. The Company also capitalized interest expense related to well development of approximately \$41 million, \$28 million and \$18 million in 2023, 2022 and 2021, respectively. Depletion expense is calculated based on actual produced sales volume multiplied by the applicable depletion rate per unit. Depletion rates for leases and wells are each calculated by dividing net capitalized costs by the number of units expected to be produced over the life of the reserves separately. Costs for exploratory dry holes, exploratory geological and geophysical activities and delay rentals as well as other property carrying costs are charged to exploration expense. The Company's producing oil and gas properties had an overall average depletion rate of \$0.84, \$0.85 and \$0.89 per Mcfe for the years ended December 31, 2023, 2022 and 2021, respectively.

There were no exploratory wells drilled during 2023, 2022 and 2021, and there were no capitalized exploratory well costs for the years ended December 31, 2023, 2022 and 2021.

Impairment of Proved Oil and Gas Properties. The carrying values of the Company's proved oil and gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. To determine whether impairment of the Company's oil and gas properties has occurred, the Company compares the estimated expected undiscounted future cash flows to the carrying values of those properties. Estimated future cash flows are based on proved and, if determined reasonable by management, risk-adjusted probable reserves and assumptions generally consistent with the assumptions used by the Company for internal planning and budgeting purposes, including, among other things, the intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil adjusted for basis differentials, future operating costs and inflation. Proved oil and gas properties that have carrying amounts in excess of estimated future undiscounted cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rates and other assumptions that marketplace participants would use in their fair value estimates. There were no indicators of impairment to the Company's material asset groups identified during 2023, 2022 and 2021.

Impairment and Expiration of Leases. Capitalized costs of unproved oil and gas properties are evaluated for recoverability on a prospective basis at least annually. Indicators of potential impairment include changes due to economic factors, potential shifts in business strategy and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches and drilling activity has not commenced. The Company recognizes impairment if the Company does not have the intent to drill on the leased property prior to expiration of the lease or does not have the intent and ability to extend, renew, trade or sell the lease prior to expiration. For the years ended December 31, 2023, 2022 and 2021, the Company recorded \$109.4 million, \$176.6 million and \$311.8 million, respectively, for impairment and expiration of leases. The Company's unproved properties had a net book value of approximately \$2,039 million and \$1,748 million as of December 31, 2023 and 2022, respectively.

Equity Method Investments. The Company applies the equity method of accounting to its investments in entities that the Company does not have the power to direct the activities that most significantly affect those entities' economic performance but does have the ability to exercise significant influence over. The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate that the investment's fair value is less than its carrying value. The recognition of an impairment loss is required if the impairment is considered other than temporary.

As of December 31, 2023, the Company held a 31% ownership interest in Laurel Mountain Midstream, LLC (LMM), which owns gathering assets that are operated by The Williams Companies, Inc., and an approximate 15.43% ownership interest in WATT Fuel Cell Corporation (WATT), a developer and manufacturer of solid oxide fuel cell stacks and systems that operate on common, readily available fuels such as propane and natural gas. As of December 31, 2023 and 2022, the carrying value of the Company's equity method investments was \$56.6 million and \$66.4 million, respectively, and was presented in other assets in the Consolidated Balance Sheets. The Company's pro-rata share of income/loss from the Company's equity method investments is recorded in (income) loss from investments in the Statements of Consolidated Operations.

Investments in Equity Securities. As of December 31, 2023, the Company held an investment in a fund (the Investment Fund) that invests in companies that develop technology and operating solutions for exploration and production companies. The Company does not have the ability to exercise significant influence over the Investment Fund and, as such, accounts for its interests in the Investment Fund as an investment in equity security. As of December 31, 2023 and 2022, the fair value of the Company's investment in the Investment Fund was \$36.1 million and \$31.2 million, respectively, and was presented in other assets in the Consolidated Balance Sheets. The Company computes the fair value of the Company's investment in the Investment Fund using, as a practical expedient, the net asset value provided in the financial statements received from fund managers. Changes in the fair value of the Company's investment in the Investment Fund are recorded in (income) loss from investments in the Statements of Consolidated Operations. Dividends received on the Company's investment in the Investment Fund are recorded in dividend and other income in the Statements of Consolidated Operations.

During 2022, the Company sold all of its then-owned shares of common stock of Equitrans Midstream Corporation (Equitrans Midstream). Prior to the Company's sale of Equitrans Midstream's common stock, the Company accounted for its investment in Equitrans Midstream as an investment in equity security. Changes in the fair value of the Company's investment in Equitrans Midstream were recorded in (income) loss from investments in the Statements of Consolidated Operations. Dividends received on the Company's investment in Equitrans Midstream were recorded in dividend and other income in the Statements of Consolidated Operations.

Contract Asset. See Note 5 for discussion of the Company's contract asset and impairment thereof.

Other Current Liabilities. The following table summarizes the Company's other current liabilities.

	December 31,	
	2023	2022
	(Thousands)	
Accrued interest payable	\$ 80,520	\$ 88,484
Accrued taxes other than income	62,391	84,755
Current portion of lease liabilities	46,380	35,449
Current portion of long-term capacity contracts	43,233	39,589
Accrued incentive compensation	24,542	50,894
Other accrued liabilities	28,457	42,320
Total other current liabilities	<u>\$ 285,523</u>	<u>\$ 341,491</u>

Unamortized Debt Discount and Issuance Expense. Discounts and expenses incurred with the issuance of debt are amortized over the life of the debt. These amounts are presented as a reduction of debt in the Consolidated Balance Sheets. See Note 8.

Income Taxes. The Company files a consolidated U.S. federal income tax return and uses the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable net of amounts refunded or estimated to be refunded for the current year and the change in deferred taxes exclusive of amounts recorded in other comprehensive loss. Any refinements to prior year taxes made in the current year due to new information are reflected as adjustments in the current period. Separate income taxes are calculated for items charged or credited directly to shareholders' equity.

Deferred tax assets and liabilities arise from temporary differences between the financial reporting and tax bases of the Company's assets and liabilities and are recognized using enacted tax rates for the effect of such temporary differences. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that a portion or all of the deferred tax asset will not be realized. When evaluating whether or not a valuation allowance should be established, the Company exercises judgment on whether it is more likely than not (a likelihood of more than 50%) that a portion or all of the deferred tax assets will not be realized. To determine whether a valuation allowance is needed, the Company considers all available evidence, both positive and negative, including carrybacks, tax planning strategies, reversals of deferred tax assets and liabilities and forecasted future taxable income.

In accounting for uncertainty of a tax position taken or expected to be taken in a tax return, the Company uses a recognition threshold and measurement attribute for the financial statement recognition and measurement. The recognition threshold requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If it is more likely than not that a tax position will be sustained, the Company measures and recognizes the tax position at the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. To determine the amount of financial statement benefit recorded for uncertain tax positions, the Company considers the amounts and probabilities of outcomes that could be realized upon ultimate settlement of an uncertain tax position using facts, circumstances and information available at the reporting date. The Company recognizes accrued interest and penalties related to unrecognized tax benefits in income tax expense. See Note 7.

Insurance. The Company maintains insurance to cover traditional insurable risks such as general liability, workers compensation, auto liability, environmental liability, property damage, business interruption, fiduciary liability, director and officers' liability and other risks. These policies may be subject to deductible or retention amounts, coverage limitations and exclusions. The Company was previously self-insured for certain material losses related to general liability, workers compensation and environmental liability; however, the Company now maintains insurance for such losses arising on or after November 12, 2020. Reserves are estimated based on analyses of historical data and actuarial estimates, where applicable, and are not discounted. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The liabilities are reviewed by the Company quarterly and by independent actuaries, where applicable, annually to ensure appropriateness.

Asset Retirement Obligations. The Company accrues a liability for asset retirement obligations based on an estimate of the amount and timing of settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is recorded at the time the obligation is incurred, which is typically at the time the well is spud. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value through charges to depreciation and depletion expense. The initial capitalized costs are depleted over the useful lives of the related assets.

The Company's asset retirement obligations related to the abandonment of oil and gas producing facilities include reclaiming well pads, reclaiming water impoundments, plugging wells and dismantling related structures. Estimates are based on historical experience of plugging and abandoning wells and reclaiming or disposing other assets and estimated remaining lives of the wells and assets.

The Company is under no legal or contractual obligation to restore or dismantle its midstream assets upon abandonment. In addition, the Company is responsible for the operation and maintenance of its midstream assets and intends to continue such operation and maintenance so long as supply and demand for natural gas exists. As the Company expects supply and demand for natural gas to exist into the foreseeable future, the Company has not recorded asset retirement obligations for its midstream assets.

The following table presents a reconciliation of the beginning and ending carrying amounts of the Company's asset retirement obligations included in other liabilities and credits in the Consolidated Balance Sheets.

	December 31,	
	2023	2022
	(Thousands)	
Balance at January 1	\$ 732,803	\$ 661,334
Accretion expense	47,700	36,613
Liabilities incurred	10,515	34,363
Liabilities settled	(33,938)	(19,055)
Liabilities assumed in acquisitions	64,424	—
Liabilities removed in divestitures	(6,480)	(697)
Change in estimates (a)	96,033	20,245
Balance at December 31	<u>\$ 911,057</u>	<u>\$ 732,803</u>

(a) During 2023, the Company recorded changes in estimates attributable primarily to inflation on estimated plugging costs.

The Company does not have any assets that are legally restricted for purposes of settling these obligations. The Company operates in several states that have implemented expanded requirements resulting in the Company's use of additional materials during the plugging process, which has increased the estimated cost for plugging horizontal and conventional wells.

Revenue Recognition. For information on revenue recognition from contracts with customers and gains and losses on derivative commodity instruments see Notes 2 and 3, respectively.

Transportation and Processing. Costs incurred to gather, process and transport gas produced by the Company to market sales points are recorded as transportation and processing costs in the Statements of Consolidated Operations. The Company markets some transportation for resale. These costs, which are not incurred to transport gas produced by the Company, are reflected as a deduction from net marketing services and other revenues.

Share-based Compensation. See Note 10 for a discussion of the Company's share-based compensation plans.

Provision for Doubtful Accounts. Reserves for uncollectible accounts are recorded in selling, general and administrative expense in the Statements of Consolidated Operations. Judgment is required to assess the ultimate realization of the Company's accounts receivable. Reserves are based on historical experience, current and expected economic trends and specific information about customer accounts, such as the customer's creditworthiness.

Other Operating Expenses. The following table summarizes the Company's other operating expenses.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Transactions	\$ 56,263	\$ 14,185	\$ 57,430
Energy transition initiatives	12,244	11,985	—
Changes in legal and environmental reserves, including settlements	9,342	30,394	5,175
Other	6,194	767	7,458
Total other operating expenses	<u>\$ 84,043</u>	<u>\$ 57,331</u>	<u>\$ 70,063</u>

Defined Contribution Plan and Other Postretirement Benefits Plan. The Company recognized expense related to its defined contribution plan of \$9.0 million, \$7.8 million and \$7.0 million for the years ended December 31, 2023, 2022 and 2021, respectively. In addition, the Company sponsors an other postretirement benefits plan.

Income Per Share. Basic income per share is computed by dividing net income (loss) attributable to EQT Corporation by the weighted average number of common shares outstanding during the period. Diluted income per share is computed by dividing the sum of net income (loss) attributable to EQT Corporation plus the applicable numerator adjustments by the weighted average number of common shares and potentially dilutive securities, net of shares assumed to be repurchased using the treasury stock method. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards as well as, prior to the Redemption (defined in Note 8), the Convertible Notes (defined in Note 8). Purchases of treasury shares are calculated using the average share price of EQT Corporation common stock during the period. Prior to the Redemption, the Company used the if-converted method to calculate the impact of the Convertible Notes on diluted income per share.

The table below provides the computation for basic and diluted income per share.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands, except per share amounts)		
Net income (loss) attributable to EQT Corporation – Basic income (loss) available to shareholders	\$ 1,735,232	\$ 1,770,965	\$ (1,142,747)
Add back: Interest expense on Convertible Notes, net of tax (a)	7,551	8,019	—
Diluted income (loss) available to shareholders	<u>\$ 1,742,783</u>	<u>\$ 1,778,984</u>	<u>\$ (1,142,747)</u>
Weighted average common stock outstanding – Basic	380,902	370,048	323,196
Options, restricted stock, performance awards and stock appreciation rights (a)	5,232	5,731	—
Convertible Notes (a)	27,090	30,716	—
Weighted average common stock outstanding – Diluted	<u>413,224</u>	<u>406,495</u>	<u>323,196</u>
Income (loss) per share of common stock attributable to EQT Corporation:			
Basic	\$ 4.56	\$ 4.79	\$ (3.54)
Diluted	\$ 4.22	\$ 4.38	\$ (3.54)

- (a) In periods when the Company reports a net loss, all options, restricted stock, performance awards and stock appreciation rights are excluded from the calculation of diluted weighted average shares outstanding because of their anti-dilutive effect on loss per share. As a result, for the year ended December 31, 2021, all such securities of 8.2 million were excluded from potentially dilutive securities because of their anti-dilutive effect on loss per share.

The Company uses the if-converted method to calculate the impact of the Convertible Notes on diluted income (loss) per share. For the year ended December 31, 2021, such if-converted securities of approximately 33.3 million were excluded from potentially dilutive securities because of their anti-dilutive effect on loss per share.

Supplemental Cash Flow Information. The following table summarizes net cash paid for interest and income taxes and non-cash activity included in the Statements of Consolidated Cash Flows.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Cash paid during the year for:			
Interest, net of amount capitalized	\$ 213,141	\$ 236,797	\$ 280,511
Income taxes, net	13,350	20,773	19,155
Non-cash activity during the period for:			
Equity issued as consideration for acquisitions (Note 6)	\$ 2,152,631	\$ —	\$ 1,925,405
Issuance of common stock for Convertible Notes settlement	122,830	63	—
Increase in asset retirement costs and obligations	106,548	54,608	15,961
Increase in right-of-use assets and lease liabilities, net	45,774	23,356	20,834
Dissolution of consolidated variable interest entity	25,227	—	—
Capitalization of non-cash equity share-based compensation	6,287	5,406	4,994

Recently Issued Accounting Standards

In November 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures* to improve reportable segment disclosure requirements, primarily through the requirement of enhanced disclosure of significant segment expenses. In addition, this ASU enhances interim disclosure requirements, clarifies circumstances in which an entity can disclose multiple segment measures of profit or loss and provides new segment disclosure requirements for entities with a single reportable segment. This ASU is effective for fiscal years beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024, and early adoption is permitted. The Company does not expect adoption of ASU 2023-07 to have a material impact on its financial statements and related disclosures.

In December 2023, the FASB issued ASU 2023-09, *Income Taxes: Improvements to Income Tax Disclosures* to improve its income tax disclosure requirements. Under this ASU, public business entities must annually (1) disclose specific categories in the rate reconciliation and (2) provide additional information for reconciling items that meet a quantitative threshold. This ASU is effective for fiscal years beginning after December 15, 2024, and early adoption is permitted. The Company does not expect adoption of ASU 2023-09 to have a material impact on its financial statements and related disclosures.

Subsequent Events. The Company has evaluated subsequent events through the date of the financial statement issuance.

2. Revenue from Contracts with Customers

Under the Company's natural gas, NGLs and oil sales contracts, the Company generally considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery. These contracts typically require payment within 25 days of the end of the calendar month in which the commodity is delivered. A significant number of these contracts contain variable consideration because the payment terms refer to market prices at future delivery dates. In these situations, the Company has not identified a standalone selling price because the terms of the variable payments relate specifically to the Company's efforts to satisfy the performance obligations. Other contracts, such as fixed price contracts or contracts with a fixed differential to New York Mercantile Exchange (NYMEX) or index prices, contain fixed consideration. The fixed consideration is allocated to each performance obligation on a relative standalone selling price basis, which requires judgment from management. For these contracts, the Company generally concludes that the fixed price or fixed differentials in the contracts are representative of the standalone selling price.

Based on management's judgment, the performance obligations for the sale of natural gas, NGLs and oil are satisfied at a point in time because the customer obtains control and legal title of the asset when the natural gas, NGLs or oil is delivered to the designated sales point.

The sales of natural gas, NGLs and oil presented in the Statements of Consolidated Operations represent the Company's share of revenues net of royalties and exclude revenue interests owned by others. When selling natural gas, NGLs and oil on behalf of royalty or working interest owners, the Company acts as an agent and, thus, reports the revenue on a net basis.

For contracts with customers where the Company's performance obligations had been satisfied and an unconditional right to consideration existed as of the balance sheet date, the Company recorded amounts due from contracts with customers of \$584.8 million and \$1,171.9 million in accounts receivable in the Consolidated Balance Sheets as of December 31, 2023 and 2022, respectively.

The table below provides disaggregated information on the Company's revenues. Certain other revenue contracts are outside the scope of ASU 2014-09, *Revenue from Contracts with Customers*. These contracts are reported in net marketing services and other in the Statements of Consolidated Operations. Derivative contracts are also outside the scope of ASU 2014-09.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Revenues from contracts with customers:			
Natural gas sales	\$ 4,520,817	\$ 11,448,293	\$ 6,180,176
NGLs sales	427,760	586,715	531,510
Oil sales	96,191	79,160	92,334
Total revenues from contracts with customers	\$ 5,044,768	\$ 12,114,168	\$ 6,804,020
Other sources of revenue:			
Gain (loss) on derivatives	\$ 1,838,941	\$ (4,642,932)	\$ (3,775,042)
Net marketing services and other	25,214	26,453	35,685
Total operating revenues	\$ 6,908,923	\$ 7,497,689	\$ 3,064,663

As of December 31, 2023, the aggregate amount of transaction price allocated to the Company's remaining performance obligations on its natural gas sales contracts with fixed consideration was \$0.5 million, which the Company expects to recognize in 2024.

3. Derivative Instruments

The Company's primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the Company's operating results. The Company uses derivative commodity instruments to hedge its cash flows from sales of produced natural gas and NGLs. The overall objective of the Company's hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices.

The derivative commodity instruments used by the Company are primarily swap, collar and option agreements. These agreements may require payments to, or receipt of payments from, counterparties based on the differential between two prices for the commodity. The Company uses these agreements to hedge its NYMEX and basis exposure. The Company may also use other contractual agreements when executing its commodity hedging strategy. The Company typically enters into over the counter (OTC) derivative commodity instruments with financial institutions, and the creditworthiness of all counterparties is regularly monitored.

The Company does not designate any of its derivative instruments as cash flow hedges; therefore, all changes in fair value of the Company's derivative instruments are recognized in operating revenues in gain (loss) on derivatives in the Statements of Consolidated Operations. The Company recognizes all derivative instruments as either assets or liabilities at fair value on a gross basis. These derivative instruments are reported as either current assets or current liabilities due to their highly liquid nature. The Company can net settle its derivative instruments at any time.

Contracts that result in physical delivery of a commodity expected to be sold by the Company in the normal course of business are generally designated as normal sales and are exempt from derivative accounting. Contracts that result in the physical receipt or delivery of a commodity but are not designated or do not meet all of the criteria to qualify for the normal purchase and normal sale scope exception are subject to derivative accounting.

The Company's OTC derivative instruments generally require settlement in cash. The Company also enters into exchange traded derivative commodity instruments that are generally settled with offsetting positions. Settlements of derivative commodity instruments are reported as a component of cash flows from operating activities in the Statements of Consolidated Cash Flows.

With respect to the derivative commodity instruments held by the Company, the Company hedged portions of its expected sales of production and portions of its basis exposure covering approximately 2,045 billion cubic feet (Bcf) of natural gas and 1,049 thousand barrels (Mbbbl) of NGLs as of December 31, 2023 and 1,424 Bcf of natural gas and 1,483 Mbbbl of NGLs as of December 31, 2022. The open positions at both December 31, 2023 and 2022 had maturities extending through December 2027.

Certain of the Company's OTC derivative instrument contracts provide that, if the Company's credit rating assigned by Moody's Investors Service, Inc. (Moody's), S&P Global Ratings (S&P) or Fitch Ratings Service (Fitch) is below the agreed-upon credit rating threshold (typically, below investment grade) and if the associated derivative liability exceeds the agreed-upon dollar threshold for such credit rating, the counterparty to such contract can require the Company to deposit collateral. Similarly, if such counterparty's credit rating assigned by Moody's, S&P or Fitch is below the agreed-upon credit rating threshold and if the associated derivative liability exceeds the agreed-upon dollar threshold for such credit rating, the Company can require the counterparty to deposit collateral with the Company. Such collateral can be up to 100% of the derivative liability. Investment grade refers to the quality of a company's credit as assessed by one or more credit rating agencies. To be considered investment grade, a company must be rated "Baa3" or higher by Moody's, "BBB-" or higher by S&P and "BBB-" or higher by Fitch. Anything below these ratings is considered non-investment grade. As of December 31, 2023, the Company's senior notes were rated "Baa3" by Moody's, "BBB-" by S&P and "BBB-" by Fitch.

When the net fair value of any of the Company's OTC derivative instrument contracts represents a liability to the Company that is in excess of the agreed-upon dollar threshold for the Company's then-applicable credit rating, the counterparty has the right to require the Company to remit funds as a margin deposit in an amount equal to the portion of the derivative liability that is in excess of the dollar threshold amount. The Company records these deposits as a current asset in the Consolidated Balance Sheets. As of December 31, 2023 and 2022, the aggregate fair value of the Company's OTC derivative instruments with credit rating risk-related contingent features that were in a net liability position was \$6.4 million and \$347.6 million, respectively, for which no deposits were required or recorded in the Consolidated Balance Sheet.

When the net fair value of any of the Company's OTC derivative instrument contracts represents an asset to the Company that is in excess of the agreed-upon dollar threshold for the counterparty's then-applicable credit rating, the Company has the right to require the counterparty to remit funds as a margin deposit in an amount equal to the portion of the derivative asset that is in excess of the dollar threshold amount. The Company records these deposits as a current liability in the Consolidated Balance Sheets. As of both December 31, 2023 and 2022, there were no such deposits recorded in the Consolidated Balance Sheets.

When the Company enters into exchange traded natural gas contracts, exchanges may require the Company to remit funds to the corresponding broker as good faith deposits to guard against the risks associated with changing market conditions. The Company is required to make such deposits based on an established initial margin requirement and the net liability position, if any, of the fair value of the associated contracts. The Company records these deposits as a current asset in the Consolidated Balance Sheets. When the fair value of such contracts is in a net asset position, the broker may remit funds to the Company. The Company records these deposits as a current liability in the Consolidated Balance Sheets. The initial margin requirements are established by the exchanges based on the price, volatility and the time to expiration of the contract. The margin requirements are subject to change at the exchanges' discretion. As of December 31, 2023 and 2022, the Company recorded \$13.0 million and \$100.6 million, respectively, of such deposits as current assets in the Consolidated Balance Sheets.

The Company has netting agreements with financial institutions and its brokers that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The table below summarizes the impact of netting agreements and margin deposits on gross derivative assets and liabilities.

	Gross derivative instruments recorded in the Consolidated Balance Sheet	Derivative instruments subject to master netting agreements	Margin requirements with counterparties	Net derivative instruments
(Thousands)				
December 31, 2023				
Asset derivative instruments, at fair value	\$ 978,634	\$ (112,203)	\$ —	\$ 866,431
Liability derivative instruments, at fair value	186,363	(112,203)	(13,017)	61,143
December 31, 2022				
Asset derivative instruments, at fair value	\$ 812,371	\$ (756,495)	\$ —	\$ 55,876
Liability derivative instruments, at fair value	1,393,487	(756,495)	(100,623)	536,369

Henry Hub Cash Bonus. The Consolidated GGA (defined in Note 5) executed in connection with the Equitrans Share Exchange (defined in Note 5) provides for cash bonus payments (the Henry Hub Cash Bonus) payable by the Company during the period beginning on the first day of the quarter in which the Mountain Valley Pipeline is placed in service and ending on the earlier of 36 months thereafter or December 31, 2024. Such payments are conditioned upon the quarterly average of the NYMEX Henry Hub natural gas settlement price exceeding certain price thresholds.

As of December 31, 2022, the Company reduced the derivative liability related to the Henry Hub Cash Bonus to zero given the uncertainties surrounding the in-service date of the Mountain Valley Pipeline and the Company's then-held belief that achieving an in-service date of the Mountain Valley Pipeline prior to December 31, 2024 was not probable.

On June 3, 2023, President Biden signed legislation that raised the United States' debt limit, ratified and approved all permits and authorizations necessary for the construction and initial operation of the Mountain Valley Pipeline and directs the applicable federal officials and agencies to maintain such authorizations. Further, the legislation requires the Secretary of the Army to issue all permits or verifications necessary to complete project construction and allow for the Mountain Valley Pipeline's operation and maintenance. During the third quarter of 2023, Equitrans Midstream resumed forward construction of the Mountain Valley Pipeline. In consideration of these factors, the Company reevaluated its probability-weighted assessment of the achievement of an in-service date of the Mountain Valley Pipeline prior to December 31, 2024 and concluded that, as of December 31, 2023, based on the facts and circumstances that existed as of that date, the derivative liability related to the Henry Hub Cash Bonus had a fair value of approximately \$48 million.

The fair value of the derivative liability related to the Henry Hub Cash Bonus is based on significant inputs that are interpolated from observable market data and, as such, is a Level 2 fair value measurement. See Note 4 for a description of the fair value hierarchy.

4. Fair Value Measurements

The Company records its financial instruments, which are principally derivative instruments, at fair value in the Consolidated Balance Sheets. The Company estimates the fair value of its financial instruments using quoted market prices when available. If quoted market prices are not available, the fair value is based on models that use market-based parameters, including forward curves, discount rates, volatilities and nonperformance risk, as inputs. Nonperformance risk considers the effect of the Company's credit standing on the fair value of liabilities and the effect of the counterparty's credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company's or counterparty's credit rating and the yield on a risk-free instrument.

The Company has categorized its assets and liabilities recorded at fair value into a three-level fair value hierarchy based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities that use Level 2 inputs primarily include the Company's swap, collar and option agreements.

Exchange traded commodity swaps have Level 1 inputs. The fair value of the commodity swaps with Level 2 inputs is based on standard industry income approach models that use significant observable inputs, including, but not limited to, NYMEX natural gas forward curves, SOFR-based discount rates, basis forward curves and NGLs forward curves. The Company's collars and options are valued using standard industry income approach option models. The significant observable inputs used by the option pricing models include NYMEX forward curves, natural gas volatilities and SOFR-based discount rates.

The table below summarizes assets and liabilities measured at fair value on a recurring basis.

	Gross derivative instruments recorded in the Consolidated Balance Sheets	Fair value measurements at reporting date using:		
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
(Thousands)				
December 31, 2023				
Asset derivative instruments, at fair value	\$ 978,634	\$ 66,302	\$ 912,332	\$ —
Liability derivative instruments, at fair value	186,363	42,218	144,145	—
December 31, 2022				
Asset derivative instruments, at fair value	\$ 812,371	\$ 103,028	\$ 709,343	\$ —
Liability derivative instruments, at fair value	1,393,487	154,601	1,238,886	—

The carrying values of cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term maturities. The carrying value of borrowings under the Company's revolving credit facility and the Term Loan Facility (defined in Note 8) approximates fair value as their interest rates are based on prevailing market rates. The Company considers all of these fair values to be Level 1 fair value measurements.

The Company estimates the fair value of its senior notes using established fair value methodology. Because not all of the Company's senior notes are actively traded, their fair value is a Level 2 fair value measurement. As of December 31, 2023 and 2022, the Company's senior notes had a fair value of approximately \$4.9 billion and \$6.1 billion, respectively, and a carrying value of approximately \$4.5 billion and \$5.6 billion, respectively, inclusive of any current portion. The fair value of the Company's note payable to EQM Midstream Partners, LP (EQM), a wholly-owned subsidiary of Equitrans Midstream, is estimated using an income approach model with a market-based discount rate and is a Level 3 fair value measurement. As of December 31, 2023 and 2022, the Company's note payable to EQM had a fair value of approximately \$91 million and \$96 million, respectively, and a carrying value of approximately \$88 million and \$94 million, respectively, inclusive of any current portion. See Note 8 for further discussion of the Company's debt.

The Company recognizes transfers between Levels as of the actual date of the event or change in circumstances that caused the transfer. There were no transfers between Levels 1, 2 and 3 during the periods presented.

See Note 3 for a discussion of the fair value measurement of the Henry Hub Cash Bonus. See Note 5 for a discussion of the fair value measurement of the Company's contract asset. See Note 6 for a discussion of the fair value measurement of the Company's acquisitions. See Note 1 for a discussion of the fair value measurement and any subsequent impairments of the Company's oil and gas properties and other long-lived assets, including impairment and expiration of leases. See Note 1 for a discussion of the fair value measurement of the Company's investment in the Investment Fund.

5. Impairment of Contract Asset

During the first quarter of 2020, the Company sold to Equitrans Midstream approximately 50% of the Company's then-owned equity interest in Equitrans Midstream in exchange for a combination of cash and rate relief under certain of the Company's gathering contracts with an affiliate of Equitrans Midstream (the Equitrans Share Exchange). The rate relief was effected through the execution of a consolidated gas gathering and compression agreement entered into between the Company and an affiliate of Equitrans Midstream (the Consolidated GGA). On the closing date of the Equitrans Share Exchange, the Company recorded in the Consolidated Balance Sheet a contract asset of \$410 million representing the estimated fair value of the rate relief inclusive of the Cash Payment Option (defined below).

Because the Mountain Valley Pipeline was not in service by January 1, 2022, the Consolidated GGA provided the Company the option to forgo a portion of the gathering fee relief that would otherwise be applicable following the Mountain Valley Pipeline in-service date in exchange for a cash payment of approximately \$196 million (the Cash Payment Option). During the third quarter of 2022, the Company elected to exercise the Cash Payment Option, and, in the fourth quarter of 2022, the Company received the cash proceeds from the Cash Payment Option.

During 2022, the Company identified indicators that the carrying value of the contract asset may not be fully recoverable, including increased uncertainty of the estimated timing of completion of the Mountain Valley Pipeline due to court rulings and public statements from Equitrans Midstream with respect to its completion. As a result of the Company's impairment evaluation, the Company recognized impairment of the contract asset during the first quarter of 2022 of \$184.9 million in the Statement of Consolidated Operations. During the fourth quarter of 2022, the Company recognized additional impairment of the contract asset of \$29.3 million in the Statement of Consolidated Operations. As of December 31, 2022, the previously recognized impairments plus the election of the Cash Payment Option reduced the carrying value of the contract asset to zero.

The fair value of the contract asset was based on significant inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. See Note 4 for a description of the fair value hierarchy. Key assumptions used in the fair value calculation included the following: (i) a probability-weighted estimate of the in-service date of the Mountain Valley Pipeline; (ii) an estimate of the potential exercise and timing of the Cash Payment Option; (iii) an estimated production volume forecast and (iv) a market-based weighted average cost of capital.

6. Acquisitions

Tug Hill and XcL Midstream Acquisition

On August 22, 2023, the Company completed its acquisition (the Tug Hill and XcL Midstream Acquisition) of the upstream assets from THQ Appalachia I, LLC (the Upstream Seller) and the gathering and processing assets from THQ-XcL Holdings I, LLC (the Midstream Seller) through the acquisition of all of the issued and outstanding membership interests of each of THQ Appalachia I Midco, LLC and THQ-XcL Holdings I Midco, LLC pursuant to the Amended and Restated Purchase Agreement, dated December 23, 2022 (as amended, the Tug Hill and XcL Midstream Purchase Agreement), entered into by and among EQT Corporation, EQT Production Company (a wholly-owned indirect subsidiary of EQT Corporation), the Upstream Seller and the Midstream Seller.

The purchase price for the Tug Hill and XcL Midstream Acquisition consisted of 49,599,796 shares of EQT Corporation common stock and approximately \$2.4 billion in cash, subject to customary post-closing adjustments. The Company funded the cash portion of the consideration with \$1.25 billion of borrowings under the Term Loan Facility, \$1.0 billion of cash on hand and the \$150 million cash deposit previously placed in escrow. The Tug Hill and XcL Midstream Purchase Agreement has an economic effective date of July 1, 2022.

As a result of the Tug Hill and XcL Midstream Acquisition, the Company acquired approximately 90,000 net West Virginia acres, approximately 145 miles of midstream gathering pipeline, compression and gas processing assets and approximately 55 miles of connected water infrastructure with four centralized storage facilities.

Allocation of Purchase Price. The Tug Hill and XcL Midstream Acquisition was accounted for as a business combination using the acquisition method. The table below summarizes the preliminary purchase price and estimated fair values of assets acquired and liabilities assumed as of August 22, 2023. Certain information necessary to complete the purchase price allocation is not yet available, including, but not limited to, final appraisals of assets acquired and liabilities assumed. The Company expects to complete the purchase price allocation once it has received all necessary information, at which time the value of the assets acquired and liabilities assumed will be revised if necessary.

	Preliminary Purchase Price Allocation	
	(Thousands)	
Consideration:		
Equity	\$	2,152,631
Cash		2,386,982
Settlement of pre-existing relationships		(31,754)
Total consideration	\$	4,507,859
Fair value of assets acquired:		
Cash and cash equivalents	\$	100
Accounts receivable, net		75,961
Derivative instruments, at fair value		162,455
Prepaid expenses and other		1,825
Property, plant and equipment		4,522,561
Other assets		9,463
Total amount attributable to assets acquired	\$	4,772,365
Fair value of liabilities assumed:		
Accounts payable	\$	151,433
Other current liabilities		46,703
Other liabilities and credits		66,370
Total amount attributable to liabilities assumed	\$	264,506

The fair value of the acquired developed natural gas and oil properties was measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include future commodity prices, projections of estimated quantities of reserves, estimated future rates of production, projected reserve recovery factors, timing and amount of future development and operating costs and a weighted average cost of capital.

The fair value of the acquired undeveloped properties was primarily measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include timing and amount of future development from a market participant perspective.

The fair value of the acquired midstream and water infrastructure assets was measured primarily using the cost approach based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include replacement costs for similar assets, relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets.

See Note 4 for a description of the fair value hierarchy.

Post-Acquisition Operating Results. The table below summarizes amounts contributed by the upstream, gathering and processing assets acquired in the Tug Hill and XcL Midstream Acquisition to the Company's consolidated results for the period from August 22, 2023 through December 31, 2023.

**August 22, 2023 through
December 31, 2023**

	(Thousands)	
Sales of natural gas, NGLs and oil	\$	220,500
Loss on derivatives		(1,039)
Net marketing services and other		1,879
Total operating revenues	\$	221,340
Net loss	\$	(26,988)

Unaudited Pro Forma Information. The table below summarizes the Company's results as though the Tug Hill and XcL Midstream Acquisition had been completed on January 1, 2022. Certain of the Upstream Seller's and Midstream Seller's historical amounts were reclassified to conform to the Company's financial presentation of operations. Such unaudited pro forma information is provided for informational purposes only and does not represent what consolidated results of operations would have been had the Tug Hill and XcL Midstream Acquisition occurred on January 1, 2022 nor are they indicative of future consolidated results of operations.

	Years Ended December 31,	
	2023	2022
	(Thousands, except per share amounts)	
Pro forma sales of natural gas, NGLs and oil	\$ 5,509,497	\$ 13,802,833
Pro forma gain (loss) on derivatives	1,996,570	(4,528,821)
Pro forma net marketing services and other	27,720	35,472
Pro forma total operating revenues	\$ 7,533,787	\$ 9,309,484
Pro forma net income	\$ 1,911,706	\$ 2,575,008
Less: Pro forma net (loss) income attributable to noncontrolling interests	(688)	9,977
Pro forma net income attributable to EQT Corporation	\$ 1,912,394	\$ 2,565,031
Pro forma income per share of common stock attributable to EQT Corporation:		
Pro forma net income attributable to EQT Corporation – Basic	\$ 5.02	\$ 6.93
Pro forma net income attributable to EQT Corporation – Diluted	\$ 4.65	\$ 6.33

NEPA Gathering System Acquisition

The Company operates and owns a 50% interest in a gathering system in northeast Pennsylvania (the NEPA Gathering System). On February 12, 2024, the Company entered into an agreement to acquire from a minority equity partner an additional 33.75% interest in the NEPA Gathering System for a purchase price of \$205 million (the NEPA Gathering System Acquisition), subject to customary post-closing adjustments, including in relation to certain preferential purchase rights of a third party pursuant to a separate construction, ownership and operation agreement between the parties thereto, which, if exercised, would reduce the Company's acquired interests to approximately 25% for a purchase price of approximately \$155 million. The closing of the NEPA Gathering System Acquisition is subject to satisfaction of customary closing conditions, including receipt of applicable regulatory approvals.

2022 Asset Acquisition

In the fourth quarter of 2022, the Company closed on the acquisition of approximately 4,600 net Marcellus acres in northeast Pennsylvania (the 2022 Asset Acquisition). The total purchase price for the acquisition was approximately \$56 million. The 2022 Asset Acquisition was accounted for as an asset acquisition and, as such, the purchase price was allocated to property, plant and equipment.

Alta Acquisition

On July 21, 2021, the Company completed its acquisition (the Alta Acquisition) of Alta Marcellus Development, LLC and ARD Operating, LLC and subsidiaries (together, the Alta Target Entities), pursuant to that certain Membership Interest Purchase Agreement, dated May 5, 2021 (the Alta Purchase Agreement), by and among EQT Corporation, EQT Acquisition HoldCo LLC (a wholly-owned indirect subsidiary of EQT Corporation), Alta Resources Development, LLC (Alta Resources) and the Alta Target Entities. The Alta Target Entities collectively held all of Alta Resources' upstream and midstream assets and liabilities. The purchase price for the Alta Acquisition consisted of approximately \$1.0 billion in cash and 98,789,388 shares of EQT Corporation common stock, subject to customary post-closing adjustments. The Alta Purchase Agreement has an economic effective date of January 1, 2021.

As a result of the Alta Acquisition, the Company acquired approximately 300,000 net Marcellus acres in northeast Pennsylvania, approximately 1.0 Bcfe per day of net production at the time of acquisition, approximately 300 miles of midstream gathering systems, approximately 100 miles of a freshwater system and a firm transportation portfolio to premium demand markets.

Allocation of Purchase Price. The Alta Acquisition was accounted for as a business combination using the acquisition method. The following table summarizes the purchase price and fair values of assets acquired and liabilities assumed as of July 21, 2021. The Company completed the purchase price allocation during the second quarter of 2022, at which time the value of the assets acquired and liabilities assumed were revised. The purchase accounting adjustments recorded in 2022 were not material to the Company's financial statements.

	Purchase Price Allocation	
	(Thousands)	
Consideration:		
Equity	\$	1,925,405
Cash		1,000,000
Total consideration	\$	2,925,405
Fair value of assets acquired:		
Cash and cash equivalents	\$	43,199
Accounts receivable, net		159,539
Property, plant and equipment		3,145,630
Other assets		6,309
Amount attributable to assets acquired	\$	3,354,677
Fair value of liabilities assumed:		
Accounts payable	\$	131,214
Derivative instruments, at fair value		169,744
Other current liabilities		10,127
Other liabilities and credits		118,187
Amount attributable to liabilities assumed	\$	429,272

The fair value of the acquired natural gas and oil properties was measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include future commodity prices, projections of estimated quantities of reserves, estimated future rates of production, projected reserve recovery factors, timing and amount of future development and operating costs and a weighted average cost of capital. The fair value of the acquired undeveloped properties was primarily measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include timing and amount of future development from a market participant perspective.

The fair value of the acquired midstream gathering systems was measured primarily using the cost approach based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include replacement costs for similar assets, relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets.

See Note 4 for a description of the fair value hierarchy.

Reliance Asset Acquisition

On April 1, 2021, the Company closed on the acquisition of certain oil and gas assets (the Reliance Asset Acquisition) from Reliance Marcellus, LLC (Reliance), pursuant to the Company's exercise of a preferential purchase right that was triggered by Northern Oil and Gas, Inc.'s acquisition of Reliance's Marcellus assets. The total purchase price for the acquisition was approximately \$69 million, and the assets acquired consisted of approximately 40 MMcfe per day of production at the time of acquisition and 4,100 net acres located in southwest Pennsylvania. The Reliance Asset Acquisition was accounted for as an asset acquisition and, as such, the purchase price was allocated to property, plant and equipment.

7. Income Taxes

The following table summarizes the Company's income tax expense (benefit).

	Years Ended December 31,		
	2023	2022	2021
(Thousands)			
Current:			
Federal	\$ (10,894)	\$ 651	\$ 911
State	(4,818)	18,457	(1,478)
Subtotal	(15,712)	19,108	(567)
Deferred:			
Federal	450,091	527,539	(316,364)
State	(65,425)	7,073	(111,106)
Subtotal	384,666	534,612	(427,470)
Total income tax expense (benefit)	<u>\$ 368,954</u>	<u>\$ 553,720</u>	<u>\$ (428,037)</u>

For the year ended December 31, 2023, the current income tax benefit related primarily to 2014 – 2017 audit settlement interest and reduction in prior year state income tax liabilities. For the year ended December 31, 2022, the current income tax expense related primarily to state income tax liabilities. For the year ended December 31, 2021, the current income tax benefit related primarily to the sale of state research and development credits.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 (IRA). The IRA establishes a 15% corporate alternative minimum tax for certain corporations and a 1% excise tax on stock repurchases made by publicly traded U.S. corporations. The IRA also includes new and renewed options for energy credits. These changes are effective for tax years beginning after December 31, 2022. The impact of these changes did not have a material impact on the Company's financial statements and disclosures.

The table below summarizes the reasons for income tax expense (benefit) differences from amounts computed at the federal statutory rate of 21% on pre-tax income.

	Years Ended December 31,					
	2023		2022		2021	
	Amount	Rate	Amount	Rate	Amount	Rate
	(Thousands)		(Thousands)		(Thousands)	
Income (loss) before income taxes	\$ 2,103,498		\$ 2,334,662		\$ (1,569,538)	
Tax at statutory rate	\$ 441,735	21.0 %	\$ 490,279	21.0 %	\$ (329,603)	21.0 %
State income taxes	50,263	2.4 %	48,970	2.1 %	(100,026)	6.4 %
Valuation allowance	(81,483)	(3.9)%	12,685	0.5 %	9,616	(0.6)%
Convertible debt repurchase premium	—	— %	35,957	1.5 %	—	— %
State law change	(21,670)	(1.0)%	(49,511)	(2.1)%	(8,496)	0.5 %
Federal and state tax credits	(4,715)	(0.2)%	(4,319)	(0.2)%	(3,079)	0.2 %
Other	(15,176)	(0.7)%	19,659	0.8 %	3,551	(0.2)%
Income tax expense (benefit)	<u>\$ 368,954</u>	17.5 %	<u>\$ 553,720</u>	23.7 %	<u>\$ (428,037)</u>	27.3 %

The Company's effective tax rate for the year ended December 31, 2023 was lower compared to the U.S. federal statutory rate due primarily to the release of valuation allowances limiting certain state deferred tax assets and net state deferred tax benefit related to a rate reduction from a Pennsylvania tax law change enacted on July 8, 2022 (the Pennsylvania Tax Legislation) and the Tug Hill and XcL Midstream Acquisition. The Pennsylvania Tax Legislation lowered the corporate net income tax rate from 9.99% to 8.99% in 2023 and by 0.5% annually thereafter until the corporate net income tax rate reaches 4.99% in 2031.

The Company's effective tax rate for the year ended December 31, 2022 was higher compared to the U.S. federal statutory rate due primarily to state taxes, including valuation allowances limiting certain state tax benefits and nondeductible repurchase premiums on the Convertible Notes, partly offset by state tax benefits related to the Pennsylvania Tax Legislation. Included in the state law change was a decrease in state net operating loss (NOL) carryforwards of \$214.1 million and a decrease in state valuation allowance on NOL carryforwards of \$198.5 million.

The Company's effective tax rate for the year ended December 31, 2021 was higher compared to the U.S. federal statutory rate due primarily to state taxes, partly offset by valuation allowances that limit certain federal and state tax benefits as well as the West Virginia tax legislation enacted on April 13, 2021 that changed the way taxable income is apportioned in West Virginia for tax years beginning on or after January 1, 2022.

The following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities.

	December 31,	
	2023	2022
(Thousands)		
Deferred tax assets:		
NOL carryforwards	\$ 740,802	\$ 580,188
Net unrealized losses	—	171,697
Federal and state capital loss carryforward	99,632	99,837
Federal tax credits	92,730	88,015
Alternative minimum tax carryforward	—	81,237
Interest disallowance limitation	59,668	304
Other	1,156	5,697
Incentive compensation and deferred compensation plans	16,854	14,586
Deferred tax assets	1,010,842	1,041,561
Valuation allowance	(290,812)	(365,140)
Net deferred tax asset	720,030	676,421
Deferred tax liabilities:		
Property, plant and equipment	(2,457,946)	(2,118,827)
Net unrealized losses	(166,905)	—
Deferred tax liabilities	(2,624,851)	(2,118,827)
Net deferred tax liability	\$ (1,904,821)	\$ (1,442,406)

During 2023, net deferred tax liability increased by \$462.4 million compared to 2022 due primarily to current year book income impact to NOLs, partly offset by the release of valuation allowance on certain state NOLs.

The following table presents the expiration periods of the NOL carryforward deferred tax assets and associated valuation allowance by jurisdiction.

	December 31,	
	2023	2022
(Thousands)		
NOL carryforwards:		
Federal (expires between 2035 and 2037)	\$ 67,958	\$ 62,931
Federal (indefinite expiration)	323,598	202,711
State (expires between 2027 and 2037)	332,153	299,933
State (indefinite expiration)	17,093	14,613
Total NOL carryforwards	\$ 740,802	\$ 580,188
Valuation allowance on NOL carryforwards:		
Federal	\$ (24,927)	\$ (23,626)
State	(156,700)	(241,638)
Total valuation allowance on NOL carryforwards	\$ (181,627)	\$ (265,264)

The Company recognizes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. All available evidence, both positive and negative, is considered when determining the need for a valuation allowance. To determine whether a valuation allowance is required, the Company uses judgement to estimate future taxable income and considers the tax consequences in the jurisdiction where such taxable income is generated as well as evidence including the Company's current financial position, actual and forecasted results of operations, the reversal of deferred tax liabilities and tax planning strategies in addition to the current and forecasted business economics of the oil and gas industry.

For 2023 and 2022, positive evidence considered included the reversals of financial-to-tax temporary differences, the implementation of and/or ability to employ various tax planning strategies and the Company's estimation of future taxable income. Negative evidence considered included historical pre-tax book losses of the Company, the uncertainty of future commodity prices and inability to generate capital gains. A review of positive and negative evidence regarding these tax benefits resulted in the conclusion that valuation allowances for certain NOLs and capital loss carryforwards were warranted as it was more likely than not that the Company would not use them prior to expiration.

During 2023, the Company concluded that the positive evidence, including the Company's change in its cumulative income position from loss to income and its forecasted income, more likely than not outweighed the negative evidence regarding the realization of the Company's deferred tax asset (DTA) for certain state tax NOL carryforwards. As a result, the Company recorded a state deferred tax benefit of \$84.9 million related to its valuation allowance for its state NOL carryforwards in the Statement of Consolidated Operations.

The Company retained a valuation allowance related to its NOLs for certain entities and jurisdictions in which it is more likely than not that the benefit from the related DTA will not be realized as well as a valuation allowance against the portion of its federal and state DTAs, such as capital losses, which may expire before being fully utilized due to the limitation to offset only capital gains.

The remaining valuation allowance not presented in the table above is related primarily to the capital loss carryforward realized with the sale of the Company's investment in Equitrans Midstream, which was a capital asset for tax purposes. Any capital losses from the sale of the investment can only be utilized to offset capital gains and are limited to being carried back 3 years and forward 5 years for potential utilization. In 2022, the Company sold the remaining portion of its investment in Equitrans Midstream, which generated a capital loss that can only be carried forward for potential future utilization. In 2021, the Company incurred an unrealized gain when adjusting its investment in Equitrans Midstream to fair value and sold a portion of such investment, which generated a capital loss that can be partly carried back to offset capital gains recognized in an earlier year, with the remainder carried forward.

As of December 31, 2023, the Company had a valuation allowance related to the capital loss carryforward of \$52.8 million for federal income tax and \$46.8 million for state income tax purposes due to the limitations on future potential utilization. As of December 31, 2022, the Company had a valuation allowance related to the capital loss carryforward of \$52.7 million for federal income tax and \$47.1 million for state income tax purposes due to the limitations on future potential utilization.

The following table reconciles the beginning and ending amount of reserve for uncertain tax positions, excluding interest and penalties.

	2023	2022	2021
	(Thousands)		
Balance at January 1	\$ 204,035	\$ 182,032	\$ 175,213
Additions for tax positions taken in current year	11,986	9,612	4,969
(Reductions) additions for tax positions taken in prior years	(883)	12,391	1,850
Reductions for tax positions settled with tax authorities	(125,941)	—	—
Balance at December 31	<u>\$ 89,197</u>	<u>\$ 204,035</u>	<u>\$ 182,032</u>

The following table presents specific line items that were included in the reserve for uncertain tax positions.

	December 31,		
	2023	2022	2021
	(Thousands)		
If recognized, effect to the effective tax rate	\$ 83,669	\$ 117,341	\$ 97,783
Recorded in the Consolidated Balance Sheet as reduction of related deferred tax asset for general business credit carryforwards and NOLs	\$ 77,013	\$ 110,744	\$ 97,160

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded interest and penalties (income) expense of approximately \$(19.8) million, \$6.7 million and \$4.2 million for the years ended December 31, 2023, 2022 and 2021, respectively. Interest and penalties of \$2.3 million and \$22.2 million were included in the Consolidated Balance Sheets as of December 31, 2023 and 2022, respectively.

As of December 31, 2023, the Company believed that, as a result of potential settlements with relevant taxing authorities, it is reasonably possible that a decrease of \$29.6 million in unrecognized tax benefits related to federal tax positions may be necessary within twelve months.

In January 2023, the Company settled its consolidated U.S. federal income tax liability with the IRS through 2017 for amounts included in the reserve for uncertain tax positions as of December 31, 2022 with minimal impact to the effective tax rate. The settlement resulted in a reduction of liabilities and deferred tax assets of \$81.2 million and forgone research and development tax credits of \$44.7 million, which are reflected in the table above. The incremental refundable alternative minimum tax credits realized with the settlement were included in the income tax receivable in the Consolidated Balance Sheet as of December 31, 2023. Periodically, the Company is also the subject of various state income tax examinations. As of December 31, 2023, with few exceptions, the Company is no longer subject to state examinations by tax authorities for years prior to 2016.

There were no material changes to the Company's methodology for accounting for unrecognized tax benefits during 2023.

8. Debt

The table below summarizes the Company's outstanding debt.

	December 31, 2023			December 31, 2022		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
(Thousands)						
Term Loan Facility due June 30, 2025 (b) (c) (d)	\$1,250,000	\$1,244,265	\$1,244,265	\$ —	\$ —	\$ —
Senior notes:						
7.42% series B notes due 2023	—	—	—	10,000	10,000	10,110
6.125% notes due February 1, 2025 (d)	601,521	600,389	605,082	911,467	908,168	915,833
5.678% notes due October 1, 2025	—	—	—	500,000	496,578	500,370
1.75% convertible notes due May 1, 2026	290,177	286,185	768,554	414,832	406,796	967,728
3.125% notes due May 15, 2026	392,915	389,978	373,261	440,857	436,198	408,454
7.75% debentures due July 15, 2026	115,000	113,716	121,590	115,000	113,218	124,874
3.90% notes due October 1, 2027	1,169,503	1,165,439	1,121,027	1,233,008	1,227,582	1,152,875
5.700% notes due April 1, 2028	500,000	490,376	509,280	500,000	493,941	505,325
5.00% notes due January 15, 2029	318,494	315,121	316,784	327,101	322,956	313,173
7.000% notes due February 1, 2030 (d)	674,800	671,020	726,645	714,800	710,138	752,670
3.625% notes due May 15, 2031	435,165	430,141	389,925	465,165	459,070	406,205
Note payable to EQM	88,483	88,483	91,063	94,320	94,320	95,667
Total debt	5,836,058	5,795,113	6,267,476	5,726,550	5,678,965	6,153,284
Less: Current portion of debt (e)	296,424	292,432	774,983	430,668	422,632	983,758
Long-term debt	<u>\$5,539,634</u>	<u>\$5,502,681</u>	<u>\$5,492,493</u>	<u>\$5,295,882</u>	<u>\$5,256,333</u>	<u>\$5,169,526</u>

- (a) For the Company's note payable to EQM, the principal value represents the carrying value. For all other debt, the principal value less the unamortized debt issuance costs and debt discounts represents the carrying value.
- (b) The carrying value of borrowings under the Term Loan Facility approximates fair value as its interest rate is based on prevailing market rates; therefore, the Company considers the fair value of the Term Loan Facility to be a Level 1 fair value measurement. The Company measures the fair value of its note payable to EQM using Level 3 inputs. For all other debt, fair value is measured using Level 2 inputs. See Note 4 for a description of the fair value hierarchy.
- (c) In January 2024, the Company amended the Term Loan Facility to, among other things, extend the maturity date from June 30, 2025 to June 30, 2026. See below for further discussion of such amendment.

- (d) Interest rates for the Term Loan Facility, the Company's senior notes due February 1, 2025 and the Company's senior notes due February 1, 2030 fluctuate based on changes to the credit ratings assigned to the Company's senior notes by Moody's, S&P and Fitch. Interest rates for the Company's other outstanding debt do not fluctuate.
- (e) As of December 31, 2023, the current portion of debt included the 1.75% convertible notes and a portion of the note payable to EQM. As of December 31, 2022, the current portion of debt included the 7.42% series B notes, the 1.75% convertible notes and a portion of the note payable to EQM.

Debt Repayments. The table below summarizes the Company's redemptions or repurchases of debt during the year ended December 31, 2023.

Debt Tranche	Principal	Premiums/ (Discounts) (a)	Accrued but Unpaid Interest	Total Cost
	(Thousands)			
6.125% notes due February 1, 2025	\$ 309,946	\$ 1,832	\$ 6,801	\$ 318,579
5.678% notes due October 1, 2025	500,000	—	6,940	506,940
3.125% notes due May 15, 2026	47,942	(3,042)	296	45,196
3.90% notes due October 1, 2027	63,505	(3,534)	781	60,752
5.00% notes due January 15, 2029	8,607	(309)	137	8,435
7.000% notes due February 1, 2030	40,000	2,736	1,313	44,049
3.625% notes due May 15, 2031	30,000	(4,011)	167	26,156
Total	\$ 1,000,000	\$ (6,328)	\$ 16,435	\$ 1,010,107

- (a) Includes third-party costs and fees paid to dealer managers and brokers.

Revolving Credit Facility. The Company has a \$2.5 billion revolving credit facility that expires on June 28, 2027. On June 28, 2022, the Company entered into the Third Amended and Restated Credit Agreement (the Third Amendment) with the lenders party thereto and PNC Bank, National Association, as administrative agent, swing line lender and L/C issuer, amending and restating the Second Amended and Restated Credit Agreement, dated as of July 31, 2017 (the Credit Agreement). The Third Amendment, among other things, (i) extends the maturity date of the commitments and loans under the Credit Agreement to June 28, 2027 and provides, at the Company's option, two one-year extensions thereafter, subject to the approval of the lenders, (ii) allows for commitment increases of up to \$500 million, subject to the agreement of the Company and new or existing lenders and (iii) allows for Base Rate Loans, Term SOFR Rate Loans, Daily Simple SOFR Loans and Swing Line Loans (each defined in the Third Amendment). Base Rate Loans bear interest at a Base Rate (as defined in the Third Amendment) plus a margin based on the Company's then current credit ratings.

The Company's revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. The Company's revolving credit facility is underwritten by a syndicate of a large group of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. No one lender of the large group of financial institutions in the syndicate for the Company's revolving credit facility holds more than 10% of the financial commitments under such facility. The large syndicate group and relatively low percentage of participation by each lender are expected to limit the Company's exposure to disruption or consolidation in the banking industry.

The Company is not required to maintain compensating bank balances. The Company's debt issuer credit ratings, as determined by Moody's, S&P or Fitch on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with the Company's revolving credit facility in addition to the interest rate charged by the lenders on any amounts borrowed against the Company's revolving credit facility; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

The Company's revolving credit facility contains various provisions that, if not complied with, could result in termination of the Company's revolving credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the Company's revolving credit facility are the maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. The Company's revolving credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. As of December 31, 2023, the Company was in compliance with all debt provisions and covenants.

As of December 31, 2023 and 2022, the Company had approximately \$15 million and \$25 million, respectively, of letters of credit outstanding under its revolving credit facility

Under the Company's revolving credit facility, for the years ended December 31, 2023, 2022 and 2021, the maximum amount of outstanding borrowings was \$269 million, \$1.3 billion and \$1.7 billion, respectively, the average daily balance was approximately \$40 million, \$466 million and \$609 million, respectively, and interest was incurred at a weighted average annual interest rate of 6.9%, 2.8% and 1.9%, respectively. For the years ended December 31, 2023, 2022 and 2021, the Company incurred commitment fees of approximately 20, 20 and 28 basis points, respectively, on the undrawn portion of its revolving credit facility to maintain credit availability.

Term Loan Facility. On November 9, 2022, the Company entered into a Credit Agreement (as amended, the Term Loan Agreement) with PNC Bank, National Association, as administrative agent, and the other lenders party thereto, under which such lenders agreed to make to the Company unsecured term loans in a single draw in an aggregate principal amount of up to \$1.25 billion (the Term Loan Facility) to partly fund the Tug Hill and XcL Midstream Acquisition. On August 21, 2023, the Company borrowed \$1.25 billion under the Term Loan Facility, receiving proceeds, net of \$7.1 million of debt issuance costs, of \$1,242.9 million. Prior to its draw on the Term Loan Facility, the Company incurred commitment fees of approximately 20 basis points on the undrawn portion of the Term Loan Facility to maintain credit availability.

At the Company's election, the term loans outstanding under the Term Loan Facility bear interest at a Term SOFR Rate plus the SOFR Adjustment or Base Rate (all terms defined in the Term Loan Agreement), each plus a margin based on the Company's credit ratings. The Company may voluntarily prepay, in whole or in part, borrowings under the Term Loan Facility without premium or penalty but subject to reimbursement of funding losses with respect to prepayment of loans that bear interest based on the Term SOFR Rate. Borrowings under the Term Loan Facility that are repaid may not be re-borrowed. During the period from August 21, 2023 through December 31, 2023, under the Term Loan Facility, interest was incurred at a weighted average annual interest rate of 6.9%.

The Term Loan Agreement contains certain representations and warranties and various affirmative and negative covenants and events of default, including (i) a restriction on the ability of the Company and certain of its subsidiaries to incur or permit liens on assets, subject to certain significant exceptions, (ii) a restriction on the ability of certain of the Company's subsidiaries to incur debt, subject to certain significant exceptions, (iii) the establishment of a maximum consolidated debt-to-total capital ratio of the Company and its subsidiaries of 65%, (iv) a limitation on certain changes to the Company's business and (v) certain restrictions related to mergers and sales of all or substantially all of the Company's assets.

On January 16, 2024, the Company entered into a third amendment to the Term Loan Agreement to, among other things, extend the maturity date of the Term Loan Agreement from June 30, 2025 to June 30, 2026. The third amendment to the Term Loan Agreement became effective on January 19, 2024 upon the Company's prepayment of \$750 million principal amount of the term loans outstanding under the Term Loan Facility, as funded by the proceeds from the Company's 5.750% senior notes issuance and cash on hand.

Senior Notes. The indentures governing the Company's long-term indebtedness contain certain restrictive financial and operating covenants, including covenants that restrict, among other things, the Company's ability to incur, as applicable, indebtedness, incur liens, enter into sale and leaseback transactions, complete acquisitions, merge, sell assets and perform certain other corporate actions. Certain of the Company's senior notes also include an offer to repurchase provision applicable upon the occurrence of certain change of control events specified in the applicable indentures. Interest rates for the Company's senior notes due February 1, 2025 and senior notes due February 1, 2030 fluctuate based on changes to the credit ratings assigned to the Company's senior notes by Moody's, S&P and Fitch. Interest rates for the Company's other outstanding senior notes do not fluctuate.

As of December 31, 2023, aggregate maturities for the Company's senior notes were zero in 2024, \$602 million in 2025, \$798 million in 2026, \$1,170 million in 2027, \$500 million in 2028 and \$1,428 million thereafter.

5.700% Senior Notes. On October 4, 2022, the Company issued \$500 million aggregate principal amount of 5.700% senior notes to partly fund the Tug Hill and XcL Midstream Acquisition. On May 10, 2023, following the receipt of the requisite consents of holders of a majority of the aggregate principal amount of the Company's 5.700% senior notes, the Company amended the mandatory redemption provision of the indenture governing the Company's outstanding 5.700% senior notes. Under the terms set forth in the consent solicitation statement, the Company paid consent fees of \$5.3 million in the aggregate to holders of outstanding 5.700% senior notes who delivered valid consents.

5.750% Senior Notes. On January 19, 2024, the Company issued \$750 million aggregate principal amount of 5.750% senior notes due February 1, 2034. The Company used the proceeds, net of \$8.2 million of debt issuance costs and underwriters' discount, of \$741.8 million to prepay a portion of the term loans outstanding under the Term Loan Facility.

Note Payable to EQM. EQM owns a preferred interest in EQT Energy Supply, LLC, a subsidiary of the Company, that is accounted for as a note payable due to the terms of the operating agreement of EQT Energy Supply, LLC. Principal amounts due for the note payable to EQM are \$6.2 million in 2024, \$6.5 million in 2025, \$6.9 million in 2026, \$7.3 million in 2027, \$7.8 million in 2028 and \$53.8 million thereafter.

Surety Bonds. As of December 31, 2022, the Company had approximately \$180 million of surety bonds outstanding, which were issued pursuant to contractual requirements as a result of the Company's then-assigned credit ratings by Moody's, S&P and Fitch. The Company had no surety bonds outstanding as of December 31, 2023.

Convertible Notes. In April 2020, the Company issued \$500 million aggregate principal amount of 1.75% convertible senior notes (the Convertible Notes).

On January 2, 2024, in accordance with the indenture governing the Convertible Notes (the Convertible Notes Indenture), the Company issued an irrevocable notice of redemption (the Redemption Notice) for all of the outstanding Convertible Notes and announced that it would redeem any of the Convertible Notes outstanding on January 17, 2024 in cash for 100% of the principal amount, plus accrued and unpaid interest on such Convertible Notes to, but excluding, such redemption date (the Redemption Price).

Pursuant to the Convertible Notes Indenture and Redemption Notice, in lieu of surrendering their Convertible Notes for redemption, certain holders of the Convertible Notes exercised their right to convert their Convertible Notes prior to the conversion deadline of 5:00 p.m., New York City time, on January 12, 2024 (the Conversion Deadline). Between January 2, 2024 and the Conversion Deadline, Convertible Notes with an aggregate principal amount of \$289.6 million were validly surrendered for conversion and 19,992,482 shares of EQT Corporation common stock were issued to the holders of such Convertible Notes. The remaining \$0.6 million in outstanding principal amount of Convertible Notes was redeemed (the Redemption) on January 17, 2024 in cash for the Redemption Price.

Prior to the Redemption, holders of the Convertible Notes had the right to convert their Convertible Notes at their option under the following circumstances:

- during any quarter as long as the last reported price of EQT Corporation common stock for at least 20 trading days (consecutive or otherwise) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding quarter is greater than or equal to 130% of the conversion price on each such trading day (the Sale Price Condition);
- during the five-business-day period after any five-consecutive-trading-day period (the measurement period) in which the trading price per \$1,000 principal amount of the Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported price of EQT Corporation common stock and the conversion rate for the Convertible Notes on each such trading day;
- if the Company calls any or all of the Convertible Notes for redemption at any time prior to the close of business on the second scheduled trading day immediately preceding such redemption date; and
- upon the occurrence of certain corporate events set forth in the Convertible Notes Indenture.

As a result of the Sale Price Condition for conversion of the Convertible Notes being satisfied as of December 31, 2023 and the delivery of the Redemption Notice, holders of the Convertible Notes were permitted to convert their Convertible Notes at their option during the period of January 1, 2024 through the Conversion Deadline, subject to the terms and conditions set forth in the Convertible Notes Indenture and Redemption Notice. In addition, the Sale Price Condition for conversion of the Convertible Notes was satisfied as of December 31, 2022, and, accordingly, holders of the Convertible Notes were permitted to convert their Convertible Notes at their option at any time during the first quarter of 2023, subject to the terms and conditions set forth in the Convertible Notes Indenture. Therefore, as of December 31, 2023 and 2022, the net carrying value of the Convertible Notes was included in current portion of debt in the Consolidated Balance Sheets.

The table below summarizes adjustments made to the conversion rate for the Convertible Notes as a result of cash dividends paid by the Company on EQT Corporation common stock during 2023.

Dividend Paid	Effective Date of Adjustment to Conversion Rate	Conversion Shares of EQT Corporation Common Stock per \$1,000 Principal Amount
First Quarter of 2023	February 17, 2023	68.0740
Second Quarter of 2023	May 9, 2023	68.3917
Third Quarter of 2023	August 8, 2023	68.6360
Fourth Quarter of 2023	November 7, 2023	68.8912

In addition, as a result of the delivery of the Redemption Notice, during the period of January 2, 2024 through the Conversion Deadline, the conversion rate was further adjusted to 69.0364 shares of EQT Corporation common stock per \$1,000 principal amount of Convertible Notes.

The table below summarizes settlements of Convertible Notes conversion right exercises for the year ended December 31, 2023 and the period from January 1, 2024 through the Conversion Deadline. The Company settled all such conversions in shares of EQT Corporation common stock. Convertible Notes conversion right exercises are accrued in the period received.

Settlement Month	Principal Converted	Shares Issued	Average Conversion Price
	(Thousands)		
January 2023	\$ 7	473	\$ 33.70
February 2023	8	541	30.77
March 2023	6	408	31.46
April 2023	58	3,948	32.01
June 2023	4	272	39.06
July 2023	10	682	40.92
September 2023	6	411	42.35
October 2023	8	547	40.52
November 2023	111,650	7,668,374	43.16
December 2023	12,264	844,878	38.04
January 2024 (a)	290,235	20,036,639	38.03

(a) Includes settlements of Convertible Notes conversion right exercises that were exercised in December 2023 but settled in January 2024.

The table below summarizes the components of interest expense related to the Convertible Notes. The effective interest rate for the Convertible Notes is 2.4%.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Contractual interest expense	\$ 6,947	\$ 8,006	\$ 8,750
Amortization of issuance costs	2,220	2,522	2,695
Total Convertible Notes interest expense	<u>\$ 9,167</u>	<u>\$ 10,528</u>	<u>\$ 11,445</u>

Capped Call Transactions. In connection with, but separate from, the issuance of the Convertible Notes, the Company entered into capped call transactions (the Capped Call Transactions) with certain financial institutions (the Capped Call Counterparties) to reduce the potential dilution to EQT Corporation common stock upon any conversion of Convertible Notes at maturity and/or offset any cash payments that the Company is required to make in excess of the principal amount of such converted notes. The Capped Call Transactions had an initial strike price of \$15.00 per share of EQT Corporation common stock and an initial cap price of \$18.75 per share of EQT Corporation common stock, each of which were subject to certain customary adjustments, including adjustments as a result of the Company paying dividends on its common stock, and were set to expire in April 2026. The Company recorded the cost to purchase the Capped Call Transactions of \$32.5 million as a reduction to shareholders' equity.

On January 18, 2024, the Company entered into separate termination agreements with each of the Capped Call Counterparties, pursuant to which the Capped Call Counterparties paid the Company an aggregate \$93.3 million (the Termination Payment), and the Capped Call Transactions were terminated. The Company received the Termination Payment on January 22, 2024. The Termination Payment was recorded as an increase to shareholders' equity.

9. Common Stock

As of December 31, 2023, the Company had reserved 16.5 million shares of authorized and unissued EQT Corporation common stock for stock compensation plans and approximately 31.5 million shares of authorized and unissued EQT Corporation common stock for settlement of the Convertible Notes.

On December 13, 2021, the Company announced that its Board of Directors approved a share repurchase program (the Share Repurchase Program) authorizing the Company to repurchase shares of outstanding EQT Corporation common stock for an aggregate purchase price of up to \$1 billion, excluding fees, commissions and expenses. On September 6, 2022, the Company announced that its Board of Directors approved a \$1 billion increase to the Share Repurchase Program, pursuant to which approval the Company is authorized to repurchase shares of outstanding EQT Corporation common stock for an aggregate purchase price of up to \$2 billion, excluding fees, commissions and expenses. The Share Repurchase Program was originally scheduled to expire on December 31, 2023; however, on April 26, 2023, the Company announced that its Board of Directors approved a one-year extension of the Share Repurchase Program. As a result of such extension, the Share Repurchase Program will expire on December 31, 2024, but it may be suspended, modified or discontinued at any time without prior notice.

	Total number of shares purchased	Aggregate purchase price (a)	Average price paid per share (a)
		(Millions)	
Year Ended December 31, 2021	1,361,668	\$ 29.4	\$ 21.56
Year Ended December 31, 2022	13,139,641	392.7	29.89
Year Ended December 31, 2023	5,906,159	200.0	33.86
Total	20,407,468	\$ 622.1	

(a) Excludes fees and broker commissions.

See Note 8 for a discussion of the Company's issuance of shares of EQT Corporation common stock for settlement of Convertible Notes conversion right exercises for the year ended December 31, 2023 and the period from January 1, 2024 through the Conversion Deadline.

In August 2023, the Company issued 49,599,796 shares of EQT Corporation common stock as part of the consideration for the Tug Hill and XcL Midstream Acquisition described in Note 6.

In July 2021, the Company issued 98,789,388 shares of EQT Corporation common stock as part of the consideration for the Alta Acquisition described in Note 6.

10. Share-Based Compensation Plans

The following table summarizes the Company's share-based compensation expense.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Incentive Performance Share Unit Programs	\$ 23,915	\$ 23,443	\$ 15,386
Restricted stock awards	20,119	23,028	19,217
Non-qualified stock options	28	221	550
Stock appreciation rights	4,056	17,406	9,183
Other programs, including non-employee director awards	3,082	3,313	3,171
Total share-based compensation expense (a)	<u>\$ 51,200</u>	<u>\$ 67,411</u>	<u>\$ 47,507</u>

(a) For the years ended December 31, 2023 and 2021, share-based compensation expense of \$3.6 million and \$4.7 million, respectively, was included in other operating expenses. There were no such costs in 2022.

The Company typically elects to fund awards paid in stock through stock acquired by the Company in the open market or from any other person, issued directly by the Company or any combination of the foregoing. Prior to 2023, the Company typically used treasury stock to fund awards paid in stock.

Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2022 was \$15.9 million. There was no cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2023 and 2021. During the years ended December 31, 2023, 2022 and 2021, share-based payment arrangements paid in stock generated tax benefits of \$16.5 million, \$4.1 million and \$1.3 million, respectively. Cash paid for taxes related to net settlement of share-based incentive awards for the years ended December 31, 2023, 2022 and 2021 were \$41.8 million, \$24.8 million and \$3.8 million, respectively.

Incentive Performance Share Unit Programs – Equity & Liability

The Management Development and Compensation Committee of the Company's Board of Directors (the Compensation Committee) has adopted the following programs under each respective Long-Term Incentive Plan (LTIP):

- 2019 Incentive Performance Share Unit Program (2019 Incentive PSU Program) under the 2014 LTIP;
- 2020 Incentive Performance Share Unit Program (2020 Incentive PSU Program) under the 2019 LTIP;
- 2021 Incentive Performance Share Unit Program (2021 Incentive PSU Program) under the 2020 LTIP;
- 2022 Incentive Performance Share Unit Program (2022 Incentive PSU Program) under the 2020 LTIP; and
- 2023 Incentive Performance Share Unit Program (2023 Incentive PSU Program) under the 2020 LTIP.

The programs noted above are collectively referred to as the Incentive PSU Programs. The 2020 Incentive PSU Program, 2021 Incentive PSU Program, 2022 Incentive PSU Program and 2023 Incentive PSU Program granted equity awards. The 2019 Incentive PSU Program granted both equity and liability awards.

The Incentive PSU Programs were established to provide long-term incentive opportunities to executives and key employees to further align their interests with those of the Company's shareholders and with the strategic objectives of the Company. The performance period for each of the awards under the Incentive PSU Programs is 36 months, with vesting occurring upon payment following the expiration of the performance period.

Executive performance incentive program awards granted in year 2019 were earned based on:

- the level of total shareholder return relative to a predefined peer group;
- the level of operating and development cost improvement; and
- return on capital employed.

Executive performance incentive program awards granted in year 2020 are earned based on:

- adjusted well costs;
- adjusted free cash flow; and
- the level of total shareholder return relative to a predefined peer group.

Executive performance incentive program awards granted in year 2021 are earned based on:

- the level of absolute total shareholder return and total shareholder return relative to a predefined peer group.

Executive performance incentive program awards granted in year 2022 are earned based on:

- the level of absolute total shareholder return and total shareholder return relative to a predefined peer group; and
- the Company's performance in achieving its 2025 net zero Scopes 1 and 2 emissions target.

Executive performance incentive program awards granted in year 2023 are earned based on:

- the level of absolute total shareholder return and total shareholder return relative to a predefined peer group.

The payout factor for the 2019 Incentive PSU Program varied between zero and 300% of the number of outstanding units contingent upon the performance metrics listed above. The 2020 Incentive PSU Program has a payout factor that ranges from zero to 150%, the 2021 Incentive PSU Program and 2023 Incentive PSU Program have a payout factor that ranges from zero to 200% and the 2022 Incentive PSU Program has a payout factor that ranges from zero to 220% (which includes the Company's performance in achieving its 2025 net zero Scopes 1 and 2 emissions target). The Company recorded the 2020 Incentive PSU Program, the 2021 Incentive PSU Program, the 2022 Incentive PSU Program, the 2023 Incentive PSU Program and the portion of the 2019 Incentive PSU Program to be settled in stock as equity awards using a grant date fair value determined through a Monte Carlo simulation, which projected the share price for the Company and its peers at the end point of the performance period. The 2019 Incentive PSU Program also included awards to be settled in cash, which are recorded at fair value as of the measurement date determined through a Monte Carlo simulation, which projected the share price for the Company and its peers at the end point of the performance period. The expected share prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate shown in the chart below. As the Incentive PSU Programs include a performance condition that affects the number of shares that will ultimately vest, the Monte Carlo simulation computed either the grant date fair value for equity awards or the measurement date fair value for liability awards for each possible performance condition outcome on the grant date for equity awards or the measurement date for liability awards. The Company reevaluates the then-probable outcome at the end of each reporting period to record expense at the probable outcome grant date fair value or measurement date fair value, as applicable. Vesting of the units under each Incentive PSU Program occurs upon payment after the end of the performance period.

The following table summarizes Incentive PSU Programs to be settled in stock and classified as equity awards.

Incentive PSU Programs – Equity Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at December 31, 2020	1,939,728	\$ 15.92	\$ 30,878,465
Granted in Period	922,260	23.44	21,617,774
Granted from Multiplier	61,076	76.53	4,674,146
Vested	<u>(168,416)</u>	76.53	<u>(12,888,876)</u>
Outstanding at December 31, 2021	2,754,648	16.08	44,281,509
Granted in Period	575,120	29.73 (b)	17,098,318
Granted from Multiplier	162,183	29.45	4,776,289
Vested	(625,563)	29.45	(18,422,830)
Forfeited	<u>(4,398)</u>	13.28	<u>(58,405)</u>
Outstanding at December 31, 2022	2,861,990	16.66	47,674,881
Granted in Period	404,790	38.79	15,701,804
Granted from Multiplier	409,383	6.56	2,685,552
Vested	(1,773,994)	6.56	(11,637,401)
Forfeited	<u>(70,616)</u>	37.59	<u>(2,654,455)</u>
Outstanding at December 31, 2023	1,831,553	\$ 28.27	\$ 51,770,381

(a) For the years ended December 31, 2021 and 2020, the Company settled total shares of 9,550 and 7,020, respectively, for Equitrans Midstream employees.

(b) The 2022 Incentive PSU Program was granted as a liability award and converted to an equity award in April 2022. The fair value determined through a Monte Carlo simulation at the time of conversion totaled \$75.32 per share, which was an increase of \$45.59 per share from fair value determined through a Monte Carlo simulation at the grant date.

The following table summarizes Incentive PSU Programs to be settled in cash and classified as liability awards.

Incentive PSU Programs – Cash Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at December 31, 2020	339,695	\$ 43.52	\$ 14,782,424
Granted from Multiplier	32,350	76.53	2,475,746
Vested	(134,525)	76.53	(10,293,571)
Forfeited	(3,940)	29.45	(116,033)
Outstanding at December 31, 2021	233,580	29.32	6,848,566
Granted from Multiplier	81,753	29.32	2,396,998
Vested	(315,333)	29.32	(9,245,564)
Outstanding at December 31, 2022	—	\$ —	\$ —

- (a) For the years ended 2021 and 2020, the Company settled total shares paid in cash of 84,697 and 40,018, respectively, for Equitrans Midstream employees.

Total capitalized compensation costs related to the Incentive PSU Programs for the years ended December 31, 2023, 2022 and 2021 were \$0.6 million, \$0.6 million and \$0.8 million, respectively. As of December 31, 2023, \$12.9 million and \$9.6 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2022 Incentive PSU Program and 2023 Incentive PSU Program, respectively, was expected to be recognized over the remainder of the performance periods.

Fair value is estimated using a Monte Carlo simulation valuation method with the following weighted average assumptions at grant date:

	Incentive PSU Programs Issued During the Years Ended December 31,				
	2023 (a)	2022	2021 (a)	2020 (b)	2019
Risk-free rate	4.16%	1.52%	0.18%	1.22%	2.44%
Volatility factor	59.31%	65.38%	72.50%	45.41%	54.60%
Expected term	3 years	3 years	3 years	3 years	3 years

- (a) There were two grant dates for the 2023 Incentive PSU Program and the 2021 Incentive PSU Program. Amounts shown represent weighted average.
- (b) There were three grant dates for the 2020 Incentive PSU Program. Amounts shown represent weighted average.

Dividends paid from the beginning of the performance period will be cumulatively added as additional shares of common stock; therefore, dividend yield is not applicable.

Restricted Stock Unit Awards

The Company granted 953,270, 1,288,430 and 1,980,230 restricted stock unit equity awards to employees of the Company during the years ended December 31, 2023, 2022 and 2021, respectively. Awards are subject to a three-year graded vesting schedule commencing with the date of grant, assuming continued service through each vesting date. For the years ended December 31, 2023, 2022 and 2021, the weighted average fair value of these restricted stock unit grants, based on the grant date fair value of EQT Corporation common stock, was approximately \$31.88, \$21.65 and \$13.92, respectively.

The total fair value of restricted stock unit equity awards vested during the years ended December 31, 2023, 2022 and 2021 was \$23.5 million, \$16.6 million and \$8.6 million, respectively. Total capitalized compensation costs related to the restricted stock unit equity awards was \$5.7 million, \$6.6 million and \$6.7 million for the years ended December 31, 2023, 2022 and 2021, respectively.

As of December 31, 2023, \$17.1 million of unrecognized compensation cost related to nonvested restricted stock unit equity awards was expected to be recognized over a remaining weighted average vesting term of approximately 0.7 years.

The following table summarizes restricted stock unit equity award activity as of December 31, 2023.

Restricted Stock – Equity Settled	Nonvested Shares	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2022	3,104,281	\$ 12.58	\$ 39,056,435
Granted	1,288,430	21.65	27,893,331
Vested	(1,368,577)	12.16	(16,644,859)
Forfeited	(97,189)	15.56	(1,512,333)
Outstanding at December 31, 2022	2,926,945	16.67	48,792,574
Granted	953,270	31.88	30,389,954
Vested	(1,544,968)	15.20	(23,482,927)
Forfeited	(117,445)	24.52	(2,879,751)
Outstanding at December 31, 2023	2,217,802	\$ 23.82	\$ 52,819,850

Non-Qualified Stock Options

The fair value of the Company's option grants was estimated at the grant date using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the year ended December 31, 2020. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of grant. The dividend yield is based on the dividend yield of EQT Corporation common stock at the time of grant. Expected volatilities are based on historical volatility of EQT Corporation common stock. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience. There were no stock options granted in 2023, 2022 and 2021.

	Year Ended December 31, 2020
Risk-free interest rate	1.10 %
Dividend yield	— %
Volatility factor	60.00 %
Expected term	4 years
Number of Options Granted	1,000,000
Weighted Average Grant Date Fair Value	\$ 1.61

The total intrinsic value of options exercised during the years ended December 31, 2023 and 2022 was \$1.4 million and \$20.2 million, respectively. There were no stock option exercises in 2021.

The following table summarizes option activity as of December 31, 2023.

Non-Qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2023	1,583,636	\$ 18.81		
Exercised	(60,100)	20.44		
Outstanding and Exercisable at December 31, 2023	1,523,536	\$ 18.75	2.7 years	\$ 31,840,100

Stock Appreciation Rights

During 2020, the Company granted stock appreciation rights subject to certain performance conditions, such as adjusted well costs and adjusted free cash flow. The participant was entitled to receive, upon exercise, a number of shares of EQT Corporation common stock, cash or a combination of the two, based upon the excess of the fair market value as of the date of exercise over a base price of \$10.00.

The awards were accounted for as liability awards and, as such, compensation expense was recorded based on the fair value of the awards as remeasured at the end of each reporting period. Assumptions at grant date are indicated in the table below. The risk-free rate was based on the U.S. Treasury yield curve in effect at the reporting date. The dividend yield was based on the dividend yield of EQT Corporation common stock at the reporting date. Expected volatilities were based on a 50-50 blend of the expected term-matched historical volatility as of the valuation date and the weighted-average implied volatility from thirty days prior to the valuation date. The expected term represents the period of time between the valuation date and the midpoint of the exercise window.

2020 Stock Appreciation Rights	
Risk-free interest rate	0.30 %
Dividend yield	— %
Volatility factor	67.50 %
Expected term	3.28 years
Number of Stock Appreciation Rights Granted	1,240,000
Weighted Average Grant Date Fair Value	\$ 2.61
Total Intrinsic Value of Exercises	\$ —

All outstanding stock appreciation rights were exercised during 2023. The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2023 was \$33.4 million. There were no exercises in 2022 or 2021.

The following table summarizes stock appreciation rights activity as of December 31, 2023.

Stock Appreciation Rights	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2023	1,240,000	\$ 10.00		
Exercised	(1,240,000)	10.00		
Outstanding and Exercisable at December 31, 2023	—	\$ —	—	\$ —

Non-employee Directors' Share-Based Awards

The Company grants to non-employee directors restricted stock unit awards that vest on the date of the Company's annual meeting of shareholders immediately following the grant of such awards. The restricted stock unit awards are settled in EQT Corporation common stock on the vesting date or, if elected by the director, following a director's termination of service on the Company's Board of Directors.

Awards granted prior to 2020 that are to be paid in cash are accounted for as liability awards and, as such, compensation expense is recorded based on the fair value of the awards as remeasured at the end of each reporting period. Awards to be settled in EQT Corporation common stock are accounted for as equity awards and, as such, compensation expense is recorded based on the fair value of the awards at the grant date fair value. A total of 421,358 non-employee director share-based awards, including accrued dividends, were outstanding as of December 31, 2023. A total of 66,300, 44,800 and 120,080 share-based awards were granted to non-employee directors during the years ended December 31, 2023, 2022 and 2021, respectively. The weighted average fair value of these grants, based on the closing price of EQT Corporation common stock on the business day prior to the grant date, was \$33.31, \$43.97 and \$17.49 for the years ended December 31, 2023, 2022 and 2021, respectively.

11. Commitments and Contingencies

Purchase Obligations

The Company has commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines as well as commitments for processing capacity. Aggregate future payments for these items as of December 31, 2023 were \$22.0 billion, composed of \$1.8 billion in 2024, \$1.8 billion in 2025, \$1.7 billion in 2026, \$1.7 billion in 2027, \$1.4 billion in 2028 and \$13.6 billion thereafter (primarily concentrated in 2029 through 2044).

In addition, the Company has commitments to pay for services and materials related to its operations, which primarily include minimum volume commitments to obtain water services and electric hydraulic fracturing services and commitments to purchase equipment, materials and sand. As of December 31, 2023, future commitments under these contracts were \$823.1 million, composed of \$228.8 million in 2024, \$164.5 million in 2025, \$138.0 million in 2026, \$111.0 million in 2027, \$72.9 million in 2028 and \$107.9 million thereafter.

See Note 13 for a summary of undiscounted future cash flows owed by the Company as lessee to lessors pursuant to contractual agreements in effect as of December 31, 2023.

Legal and Regulatory Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings.

The Company evaluates its legal proceedings, including litigation and regulatory and governmental investigations and inquiries, on a regular basis and accrues a liability for such matters when the Company believes that a loss is probable and the amount of the loss can be reasonably estimated. Any such accruals are adjusted thereafter as appropriate to reflect changed circumstances. In the event the Company determines that (i) a loss to the Company is probable but the amount of the loss cannot be reasonably estimated, or (ii) a loss to the Company is less likely than probable but is reasonably possible, then the Company is required to disclose the matter herein, although the Company is not required to accrue such loss.

When able, the Company determines an estimate of reasonably possible losses or ranges of reasonably possible losses, whether in excess of any related accrued liability or where there is no accrued liability, for legal proceedings. In instances where such estimates can be made, any such estimates are based on the Company's analysis of currently available information and are subject to significant judgment and a variety of assumptions and uncertainties and may change as new information is obtained.

The ultimate outcome of the matters described below, such as whether the likelihood of loss is remote, reasonably possible, or probable, or if and when the range of loss is reasonably estimable, is inherently uncertain. Furthermore, due to the inherent subjectivity of the assessments and unpredictability of outcomes of legal proceedings, any amounts accrued or estimated as possible losses may not represent the ultimate loss to the Company from the legal proceedings in question and the Company's exposure and ultimate losses may be higher, and possibly significantly so, than the amounts accrued or estimated.

Securities Class Action Litigation. On December 6, 2019, an amended putative class action complaint was filed in the United States District Court for the Western District of Pennsylvania by Cambridge Retirement System, Government of Guam Retirement Fund, Northeast Carpenters Annuity Fund, and Northeast Carpenters Pension Fund, on behalf of themselves and all those similarly situated, against EQT Corporation, and certain former executives and current and former board members of EQT Corporation (the Securities Class Action). The complaint alleges that certain statements made by EQT Corporation regarding its merger with Rice Energy Inc. in 2017 (the Rice Merger) were materially false and violated various federal securities laws. Pursuant to the complaint, the plaintiffs seek compensatory or rescissory damages in an unspecified amount for all damages allegedly sustained by the class as a result of alleged negative impacts to EQT Corporation's stock price in 2018 and 2019. This legal proceeding is currently in discovery and a trial date has not been determined.

Additionally, following the filing of the Securities Class Action complaint, several other lawsuits were filed in the United States District Court for the Western District of Pennsylvania and the Court of Common Pleas of Allegheny County, Pennsylvania by certain shareholders of EQT Corporation against EQT Corporation and certain former executives and current and former board members of EQT Corporation asserting substantially the same allegations as those raised in the Securities Class Action. These matters are currently pending, the majority of which have been stayed pending a ruling on dispositive motions in the Securities Class Action. The Company believes it will prevail against the claims asserted in the Securities Class Action and related litigation, but unpredictability is inherent in litigation and the Company cannot predict the outcomes with any certainty.

With respect to the matters described above, the Company is unable at this time to estimate the losses that are reasonably possible to be incurred or a range of such losses due to various factors, including that the proceedings are still in their early stages and discovery is not complete; the matters present meaningful legal uncertainties; and predicting the outcome depends on making assumptions about future decisions of courts and the behavior of other parties for which the Company does not currently have sufficient information. The matters described above contain certain information related to claims against the Company as alleged in pleadings. While information of this type may provide insight into the potential magnitude of a matter, it does not necessarily represent the Company's estimate of a probable or reasonably possible loss or the Company's judgment as to any currently appropriate accrual.

Regulatory and Environmental Matters. The Company is subject to various federal, state and local environmental and environmentally-related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may result in the assessment of fines. The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Company's financial position, results of operations or liquidity. The Company has identified situations that require remedial action for which approximately \$5.0 million was recorded in other liabilities and credits in the Consolidated Balance Sheet as of December 31, 2023.

Other Matters. In addition to the matters described above, the Company, in the normal course of business, is subject to various other pending and threatened legal proceedings in which claims for monetary damages or other relief are asserted. The Company does not anticipate, at the present time, that the ultimate aggregate liability, if any, arising out of such other legal proceedings will have a material adverse effect on the Company's financial position, results of operations or liquidity.

12. Concentrations of Credit Risk

Revenues and related accounts receivable from the Company's operations are generated primarily from the sale of produced natural gas, NGLs and oil to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through the Company's transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States and Canada. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company. The Company does not depend on any single customer and believes that the loss of any one customer would not have an adverse effect on the Company's ability to sell its natural gas, NGLs and oil.

Approximately 93% and 91% of the Company's accounts receivable balances as of December 31, 2023 and 2022, respectively, represent amounts due from non-end users. The Company manages the credit risk of sales to non-end users by limiting its dealings with only non-end users that meet the Company's criteria for credit and liquidity strength and by regularly monitoring these accounts. The Company may require letters of credit, guarantees, performance bonds or other credit enhancements from a non-end user for that non-end user to meet the Company's credit criteria. The Company did not experience any significant defaults on sales of natural gas to non-end users during the years ended December 31, 2023, 2022 and 2021.

The Company is exposed to credit loss in the event of nonperformance by counterparties to its derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company's OTC derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as the financial industry as a whole. The Company uses various processes and analyses to monitor and evaluate its credit risk exposures, including monitoring current market conditions and counterparty credit fundamentals. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions primarily with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

As of December 31, 2023, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to its derivative contracts. During the year ended December 31, 2023, the Company made no adjustments to the fair value of its derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company's established fair value procedure. The Company monitors market conditions that may impact the fair value of its derivative contracts.

13. Leases

The Company leases drilling rigs, facilities, vehicles and drilling and compression equipment.

To determine the present value of its right-of-use assets and lease liabilities, the Company calculates a discount rate per lease contract based on an estimate of the rate of interest that the Company would pay to borrow (on a collateralized basis, over a similar term) an amount equal to the lease payment obligation.

The Company has elected a practical expedient to forgo application of the recognition requirements under ASU 2016-02, *Leases*, to short-term leases; as such, short-term leases are not recorded in the Consolidated Balance Sheets. In addition, the Company has elected a practical expedient to account for lease and nonlease components together as a lease.

Certain of the Company's lease contracts include variable lease payments, such as payments for property taxes and other operating and maintenance expenses and payments based on asset use, which are not included in the lease cost or the present value of the right-of-use asset or lease liability. Certain of the Company's lease contracts provide renewal periods at the Company's option; if a renewal period option is reasonably assured to be exercised, the associated lease payment obligation is included in the present value of the right-of-use asset and lease liability. As of December 31, 2023 and 2022, the Company was not a lessor.

The following table summarizes the Company's lease costs.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Operating and finance lease costs	\$ 29,169	\$ 21,638	\$ 19,826
Variable and short-term lease costs	24,151	13,726	11,516
Total lease costs (a)	<u>\$ 53,320</u>	<u>\$ 35,364</u>	<u>\$ 31,342</u>

- (a) Includes drilling rig lease costs capitalized to property, plant and equipment of \$40.8 million, \$25.4 million and \$22.1 million, respectively, of which \$24.5 million, \$17.7 million and \$16.5 million, respectively, were operating lease costs for the years ended December 31, 2023, 2022 and 2021.

For the years ended December 31, 2023, 2022 and 2021, cash paid for lease liabilities and reported in net cash provided by operating activities in the Statements of Consolidated Cash Flows was \$10.1 million, \$10.3 million and \$9.7 million, respectively. For the years ended December 31, 2023, 2022 and 2021, cash paid for lease liabilities and reported in net cash (used in) provided by financing activities in the Statements of Consolidated Cash Flows was \$2.3 million, \$1.8 million and \$1.1 million, respectively. As of December 31, 2023, 2022 and 2021, the weighted average remaining lease term was 1.8 years, 1.9 years and 2.6 years, respectively. For the years ended December 31, 2023, 2022 and 2021, the weighted average discount rate was 4.7%, 4.4% and 2.9%, respectively.

The Company records its right-of-use assets in other assets and the current and noncurrent portions of its lease liabilities in other current liabilities and other liabilities and credits, respectively, in the Consolidated Balance Sheets. As of December 31, 2023 and 2022, total right-of-use assets were \$48.8 million and \$29.2 million, respectively, and total lease liabilities were \$58.6 million and \$48.0 million, respectively, of which \$46.4 million and \$35.4 million, respectively, were classified as current.

The following table summarizes the Company's lease payment obligations as of December 31, 2023.

	December 31, 2023	
	(Thousands)	
2024	\$	47,865
2025		7,805
2026		2,459
2027		1,742
2028		1,102
Thereafter		415
Total lease payment obligations		61,388
Less: Interest		2,811
Present value of lease liabilities	\$	<u>58,577</u>

14. Natural Gas Producing Activities (Unaudited)

The following supplementary information presents a summary of the results of natural gas and oil activities in accordance with the successful efforts method of accounting for production activities.

Production Costs

The following tables present total aggregate capitalized costs and costs incurred related to natural gas, NGLs and oil production activities.

	December 31,	
	2023	2022
	(Thousands)	
Capitalized costs		
Proved properties	\$ 30,471,164	\$ 25,142,857
Unproved properties	2,039,431	1,747,705
Total capitalized costs	32,510,595	26,890,562
Less: Accumulated depreciation and depletion	10,734,099	9,119,553
Net capitalized costs	<u>\$ 21,776,496</u>	<u>\$ 17,771,009</u>

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Costs incurred (a)			
Property acquisition:			
Proved properties (b)	\$ 4,142,621	\$ 82,276	\$ 2,544,316
Unproved properties (c)	575,130	113,523	805,942
Exploration	3,330	3,438	24,403
Development	1,782,428	1,298,665	954,580

- (a) Amounts exclude costs for facilities, information technology and other corporate items and include costs for midstream assets.
- (b) Amounts in 2023 include \$2,522.3 million, \$757.6 million and \$719.6 million for wells, midstream assets and leases, respectively, acquired in the Tug Hill and XcL Midstream Acquisition described in Note 6. Amounts in 2022 include \$40.5 million for leases acquired in the 2022 Asset Acquisition. Amounts in 2021 include \$1,754.7 million, \$257.9 million and \$450.0 million for wells, midstream assets and leases, respectively, acquired in the Alta Acquisition and Reliance Asset Acquisition described in Note 6.
- (c) Amounts in 2023 include \$523.0 million for unproved properties acquired in the Tug Hill and XcL Midstream Acquisition. Amounts in 2022 include \$17.1 million for unproved properties acquired in the 2022 Asset Acquisition. Amounts in 2021 include \$743.3 million for unproved properties acquired in the Alta Acquisition.

Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas, NGLs and oil production.

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Sales of natural gas, NGLs and oil	\$ 5,044,768	\$ 12,114,168	\$ 6,804,020
Transportation and processing	2,157,260	2,116,976	1,942,165
Production	254,700	300,985	225,279
Exploration	3,330	3,438	24,403
Depreciation and depletion	1,732,142	1,665,962	1,676,702
Loss (gain) on sale/exchange of long-lived assets	17,445	(8,446)	(21,124)
Impairment and expiration of leases	109,421	176,606	311,835
Income tax expense	187,463	1,987,323	667,435
Results of operations from producing activities, excluding corporate overhead	<u>\$ 583,007</u>	<u>\$ 5,871,324</u>	<u>\$ 1,977,325</u>

Reserve Information

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred.

The Company's estimate of proved natural gas, NGLs and oil reserves was prepared by Company engineers. The engineer primarily responsible for overseeing the preparation of the reserves estimate holds a bachelor's degree in chemical engineering from Michigan Technological University, a master's degree in chemical engineering from Colorado State University, an Executive Master of Business Administration in energy from the University of Oklahoma and is a licensed professional engineer with 24 years of experience in the oil and gas industry. To support the accurate and timely preparation and disclosure of its reserve estimates, the Company established internal controls over its reserve estimation processes and procedures, including the following: the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves are reviewed by management; division of interest and production volume are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserves reconciliation between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas, NGLs and oil reserves are audited by Netherland, Sewell & Associates, Inc. (NSAI), an independent consulting firm hired by management. Since 1961, NSAI has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

In the course of its audit, NSAI conducted a detailed review of 100% of the total net natural gas, NGLs and oil proved reserves attributable to the Company's interests as of December 31, 2023. NSAI conducted a detailed, well-by-well audit of all the Company's properties. The estimates prepared by the Company and audited by NSAI were within the recommended 10% tolerance threshold set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy and material balance were utilized in the evaluation of reserves. All of the Company's proved reserves are located in the United States.

The Company utilizes reliable technologies in the calculation of its proved undeveloped reserves. The technologies used in the estimation of the Company's proved undeveloped reserves include, but are not limited to, empirical evidence through drilling results and well performance, production data, decline curve analysis, well logs, geologic maps, core data, seismic data, demonstrated relationship between geologic parameters and performance, and the implementation and application of statistical analysis.

For all tables presented, NGLs and oil were converted at a rate of one Mbbbl to approximately six million cubic feet (MMcf).

	Years Ended December 31,		
	2023	2022	2021
	(MMcf)		
Natural gas, NGLs and oil			
Proved developed and undeveloped reserves:			
Balance at January 1	25,002,589	24,961,499	19,802,092
Revision of previous estimates	(1,402,039)	(654,618)	(274,111)
Purchase of hydrocarbons in place	2,600,667	141,038	4,186,933
Extensions, discoveries and other additions	3,411,750	2,494,713	3,104,402
Production	(2,016,273)	(1,940,043)	(1,857,817)
Balance at December 31	<u>27,596,694</u>	<u>25,002,589</u>	<u>24,961,499</u>
Proved developed reserves:			
Balance at January 1	17,513,645	17,218,655	13,641,345
Balance at December 31	19,558,176	17,513,645	17,218,655
Proved undeveloped reserves:			
Balance at January 1	7,488,944	7,742,844	6,160,747
Balance at December 31	8,038,518	7,488,944	7,742,844

	Years Ended December 31,		
	2023	2022	2021
	(MMcf)		
Natural gas			
Proved developed and undeveloped reserves:			
Balance at January 1	23,824,887	23,523,665	18,865,013
Revision of previous estimates	(1,461,305)	(432,315)	(568,814)
Purchase of natural gas in place	2,012,159	141,038	4,186,933
Extensions, discoveries and other additions	3,326,736	2,434,543	2,786,850
Production	(1,907,343)	(1,842,044)	(1,746,317)
Balance at December 31	<u>25,795,134</u>	<u>23,824,887</u>	<u>23,523,665</u>
Proved developed reserves:			
Balance at January 1	16,541,017	16,152,083	12,750,312
Balance at December 31	18,186,432	16,541,017	16,152,083
Proved undeveloped reserves:			
Balance at January 1	7,283,870	7,371,582	6,114,701
Balance at December 31	7,608,702	7,283,870	7,371,582

	Years Ended December 31,		
	2023	2022	2021
	(Mbbl)		
NGLs			
Proved developed and undeveloped reserves:			
Balance at January 1	186,141	225,792	148,762
Revision of previous estimates	11,558	(33,955)	46,868
Purchase of NGLs in place	90,604	—	—
Extensions, discoveries and other additions	13,592	9,610	47,120
Production	(16,550)	(15,306)	(16,958)
Balance at December 31	<u>285,345</u>	<u>186,141</u>	<u>225,792</u>
Proved developed reserves:			
Balance at January 1	154,921	169,781	141,489
Balance at December 31	218,523	154,921	169,781
Proved undeveloped reserves:			
Balance at January 1	31,220	56,011	7,273
Balance at December 31	66,822	31,220	56,011

	Years Ended December 31,		
	2023	2022	2021
	(Mbbl)		
Oil			
Proved developed and undeveloped reserves:			
Balance at January 1	10,142	13,846	7,417
Revision of previous estimates	(1,680)	(3,095)	2,249
Purchase of oil in place	7,481	—	—
Extensions, discoveries and other additions	577	418	5,805
Production	(1,605)	(1,027)	(1,625)
Balance at December 31	<u>14,915</u>	<u>10,142</u>	<u>13,846</u>
Proved developed reserves:			
Balance at January 1	7,183	7,981	7,016
Balance at December 31	10,101	7,183	7,981
Proved undeveloped reserves:			
Balance at January 1	2,959	5,865	401
Balance at December 31	4,814	2,959	5,865

The change in reserves during the year ended December 31, 2023 resulted from the following:

- Conversions of 2,561 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,412 Bcfe, which exceeded 2023 production of 2,016 Bcfe. Extensions, discoveries and other additions included an increase of 1,670 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2023 reserve development that expanded the number of the Company's proven locations and additions to the Company's five-year drilling plan, 1,341 Bcfe of proved undeveloped additions for previously proved undeveloped properties reclassified from unproved properties due to their addition to the Company's five-year development plan, positive revisions of 92 Bcfe from the extension of lateral lengths of proved undeveloped reserves and 309 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 755 Bcfe related to proved undeveloped locations that are no longer expected to be developed as proved reserves within five years of initial booking as a result of development schedule changes.
- Negative revisions of 367 Bcfe primarily from proved undeveloped locations as a result of revisions to type curves.
- Positive revisions to proved undeveloped locations of 290 Bcfe due primarily to changes in ownership interests.
- Negative revisions of 208 Bcfe primarily from proved developed locations as a result of negative curve revisions.

- Negative revisions of 362 Bcfe from lower pricing that impacted well economics.
- Purchase of hydrocarbons in place of 2,600 Bcfe from the Tug Hill and XcL Midstream Acquisition described in Note 6.

The change in reserves during the year ended December 31, 2022 resulted from the following:

- Conversions of 1,365 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 2,495 Bcfe, which exceeded 2022 production of 1,940 Bcfe. Extensions, discoveries and other additions included an increase of 2,077 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2022 reserve development that expanded the number of the Company's proven locations and additions to the Company's five-year drilling plan and 418 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 1,625 Bcfe related to proved undeveloped locations that are no longer expected to be developed as proved reserves within five years of initial booking as a result of development schedule changes, driven largely by third-party impacts, which have pushed planned completion dates into a future period from when originally planned.
- Positive revisions to proved undeveloped locations of 518 Bcfe due primarily to changes in ownership interests.
- Positive revisions of 356 Bcfe primarily from proved developed locations as a result of positive curve revisions.
- Positive revisions of 96 Bcfe from higher pricing that impacted well economics.
- Purchase of hydrocarbons in place of 141 Bcfe from the 2022 Asset Acquisition described in Note 6.

The change in reserves during the year ended December 31, 2021 resulted from the following:

- Conversions of 1,634 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,104 Bcfe, which exceeded 2021 production of 1,858 Bcfe. Extensions, discoveries and other additions included an increase of 2,828 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2021 reserve development that expanded the number of the Company's proven locations, implementation of, and alignment with, the Company's combo-development strategy and additions to the Company's five-year drilling plan, 52 Bcfe from extension of proved undeveloped reserves lateral lengths and 224 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 819 Bcfe from proved undeveloped locations that are no longer expected to be developed within five years of initial booking as proved reserves as a result of revisions to the Company's five-year drilling plan allowing for continued alignment with the Company's combo-development strategy.
- Negative revisions to proved undeveloped locations of 62 Bcfe due primarily to changes in working interests and net revenue interest.
- Negative revisions of 31 Bcfe primarily from proved developed locations as a result of negative curve revisions.
- Positive revisions of 638 Bcfe from higher pricing that impacted well economics.
- Purchase of hydrocarbons in place of 4,187 Bcfe from the Alta Acquisition and Reliance Asset Acquisition described in Note 6.

Standard Measure of Discounted Future Cash Flow

Management cautions that the standard measure of discounted future cash flows should not be viewed as an indication of the fair market value of natural gas and oil producing properties, nor of the future cash flows expected to be generated therefrom. The information presented does not give recognition to future changes in estimated reserves, selling prices or costs and has been discounted at a rate of 10%.

The following table summarizes estimated future net cash flows from natural gas and oil reserves.

	December 31,		
	2023	2022	2021
	(Thousands)		
Future cash inflows (a)	\$ 52,916,665	\$ 140,032,653	\$ 70,844,136
Future production costs (b)	(24,357,033)	(22,801,652)	(20,961,576)
Future development costs	(4,298,372)	(3,244,211)	(2,882,921)
Future income tax expenses	(5,230,629)	(26,375,241)	(10,433,091)
Future net cash flow	19,030,631	87,611,549	36,566,548
10% annual discount for estimated timing of cash flows	(9,768,282)	(47,547,025)	(19,285,424)
Standardized measure of discounted future net cash flows	<u>\$ 9,262,349</u>	<u>\$ 40,064,524</u>	<u>\$ 17,281,124</u>

- (a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. Reserves were computed using average first-day-of-the-month closing prices for the prior twelve months less regional adjustments. Regional adjustments were calculated using historical average realized prices received in the Appalachian Basin. NGLs pricing was calculated using average first-day-of-the-month closing prices for the prior twelve months for NGLs components, adjusted using the regional component makeup of proved NGLs.

	December 31,		
	2023	2022	2021
Oil for West Texas Intermediate (WTI) (\$/Bbl)	\$ 78.21	\$ 94.14	\$ 66.55
Less regional adjustments (\$/Bbl)	14.35	17.31	14.98
Oil price (\$/Bbl)	63.86	76.83	51.57
Natural gas for NYMEX (\$/MMBtu)	2.637	6.357	3.598
Less regional adjustments (\$/MMBtu)	1.029	1.094	1.040
Natural gas price (\$/Mcf)	1.700	5.543	2.694
NGLs price (\$/Bbl)	28.44	38.66	29.95

- (b) Includes approximately \$2,443 million, \$2,098 million and \$1,937 million for future plugging and abandonment costs as of December 31, 2023, 2022 and 2021, respectively.

Holding production and development costs constant, an increase in NYMEX price of \$0.10 per Dth for natural gas, an increase in WTI price of \$10 per barrel for NGLs and an increase in WTI price of \$10 per barrel for oil would result in a change in the December 31, 2023 discounted future net cash flows before income taxes of the Company's proved reserves of approximately \$1,260 million, \$1,214 million and \$77 million, respectively.

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

	Years Ended December 31,		
	2023	2022	2021
	(Thousands)		
Net sales and transfers of natural gas and oil produced	\$ (2,632,808)	\$ (9,696,207)	\$ (4,636,576)
Net changes in prices, production and development costs	(48,739,248)	35,353,172	17,290,913
Extensions, discoveries and improved recovery, net of related costs	6,347,387	1,798,851	46,078
Development costs incurred	1,296,380	902,925	764,002
Net purchase of minerals in place	2,131,567	280,233	3,491,441
Revisions of previous quantity estimates	(2,768,922)	(299,423)	184,552
Accretion of discount	4,006,452	1,728,112	336,646
Net change in income taxes	9,190,460	(7,233,051)	(3,614,029)
Timing and other	366,557	(51,212)	51,639
Net (decrease) increase	(30,802,175)	22,783,400	13,914,666
Balance at January 1	40,064,524	17,281,124	3,366,458
Balance at December 31	<u>\$ 9,262,349</u>	<u>\$ 40,064,524</u>	<u>\$ 17,281,124</u>

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our Principal Executive Officer and Principal Financial Officer, an evaluation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was conducted as of the end of the period covered by this report. Based on that evaluation, the Principal Executive Officer and Principal Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act). Our internal control system is designed to provide reasonable assurance to management and our Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2023. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control – Integrated Framework (2013). Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as of December 31, 2023.

Ernst & Young LLP (Ernst & Young), the independent registered public accounting firm that audited our Consolidated Financial Statements, has issued an attestation report on our internal control over financial reporting. Ernst & Young's attestation report on our internal control over financial reporting appears in Part II, Item 8., of this Annual Report on Form 10-K and is incorporated herein by reference.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

During the three months ended December 31, 2023, none of our directors or "officers" (as defined in Rule 16a-1(f) under the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement" (as each term is defined in Item 408(a) of Regulation S-K).

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from our definitive proxy statement relating to the 2024 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2023:

- Information required by Item 401 of Regulation S-K with respect to directors;
- Information required by Item 405 of Regulation S-K with respect to our compliance with Section 16(a) of the Exchange Act, if any;
- Information required by Item 407(d)(4) of Regulation S-K with respect to disclosure of the existence of our separately-designated standing Audit Committee and the identification of the members of the Audit Committee; and
- Information required by Item 407(d)(5) of Regulation S-K with respect to disclosure of our Audit Committee financial expert.

Information required by Item 401 of Regulation S-K with respect to executive officers is included after Item 4 at the end of Part I of this Annual Report on Form 10-K under the caption "Information about our Executive Officers (as of February 14, 2024)."

We have adopted a code of business conduct and ethics applicable to all directors and employees, including the principal executive officer, principal financial officer and principal accounting officer. Our code of business conduct and ethics is posted on our website <http://www.eqt.com> (accessible by clicking on the "About" link on the main page, followed by the "Governance" heading, then the "Charters and Governance Documents" link), and a printed copy will be delivered free of charge on request by writing to the Corporate Secretary at EQT Corporation, c/o Corporate Secretary, 625 Liberty Avenue, Suite 1700, Pittsburgh, Pennsylvania 15222. We intend to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of our code of business conduct and ethics by posting such information on our website.

Item 11. Executive Compensation

The following information is incorporated herein by reference from our definitive proxy statement relating to the 2024 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2023:

- Information required by Item 402 of Regulation S-K with respect to named executive officer and director compensation; and
- Information required by paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K with respect to certain matters related to the Management Development and Compensation Committee of our Board of Directors.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 403 of Regulation S-K with respect to stock ownership of significant shareholders, directors and executive officers is incorporated herein by reference from our definitive proxy statement relating to the 2024 annual meeting of shareholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2023.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2023 with respect to shares of our common stock that may be issued under our existing equity compensation plans, including the 2020 Long-Term Incentive Plan (2020 LTIP), 2019 Long-Term Incentive Plan (2019 LTIP), 2014 Long-Term Incentive Plan (2014 LTIP), the 2009 Long-Term Incentive Plan (2009 LTIP), the 2008 Employee Stock Purchase Plan (2008 ESPP), and the 2005 Directors' Deferred Compensation Plan (2005 DDCP):

Plan Category	Number Of Securities To Be Issued Upon Exercise Of Outstanding Options, Warrants and Rights (A)	Weighted Average Exercise Price Of Outstanding Options, Warrants and Rights (B)	Number Of Securities Remaining Available For Future Issuance Under Equity Compensation Plans, Excluding Securities Reflected In Column A (C)
Equity Compensation Plans Approved by Shareholders (1)	5,822,737 (2)	\$ 18.75 (3)	15,640,280 (4)
Equity Compensation Plans Not Approved by Shareholders (5)	69,775 (6)	N/A	107,061 (7)
Total	<u>5,892,512</u>	<u>\$ 18.75</u>	<u>15,747,341</u>

- (1) Consists of the 2020 LTIP, 2019 LTIP, 2014 LTIP, 2009 LTIP, and the 2008 ESPP. Effective as of May 1, 2020, with the adoption of the 2020 LTIP, we ceased making new grants under the 2019 LTIP. Effective as of July 10, 2019 in connection with the adoption of the 2019 LTIP, we ceased making new grants under the 2014 LTIP. Effective as of April 30, 2014, in connection with the adoption of the 2014 LTIP, we ceased making new grants under the 2009 LTIP. The 2019 LTIP, 2014 LTIP, and the 2009 LTIP remain effective solely for the purpose of issuing shares upon the exercise or payout of awards outstanding under such plans on May 1, 2020 (for the 2019 LTIP), July 10, 2019 (for the 2014 LTIP) and April 30, 2014 (for the 2009 LTIP).
- (2) Consists of (i) 3,958,316 shares subject to outstanding performance awards under the 2020 LTIP, inclusive of dividend reinvestments thereon (counted at a 2X multiple assuming maximum performance is achieved under the awards (representing 1,920,768 target awards and dividend reinvestments thereon)), (ii) 186,341 shares subject to outstanding directors' deferred stock units under the 2020 LTIP, inclusive of dividend reinvestments thereon, (iii) 1,000,000 shares subject to outstanding stock options under the 2019 LTIP, (iv) 40,661 shares subject to outstanding directors' deferred stock units under the 2019 LTIP, inclusive of dividend reinvestments thereon, (v) 388,231 shares subject to outstanding stock options under the 2014 LTIP, (vi) 63,122 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon, (vii) 176,886 shares subject to outstanding stock options under the 2009 LTIP; and (viii) 9,180 shares subject to outstanding directors' deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon.
- (3) The weighted-average exercise price is calculated solely based on outstanding stock options under the 2019 LTIP, 2014 LTIP and the 2009 LTIP and excludes deferred stock units under the 2020 LTIP, 2019 LTIP, 2014 LTIP and the 2009 LTIP and performance awards under the 2020 LTIP, 2019 LTIP and 2014 LTIP. The weighted average remaining term of the outstanding stock options was 2.7 years as of December 31, 2023.
- (4) Consists of (i) 15,464,915 shares available for future issuance under the 2020 LTIP and (ii) 175,365 shares available for future issuance under the 2008 ESPP. As of December 31, 2023, no shares were subject to purchase under the 2008 ESPP.
- (5) Consists of the 2005 DDCP which is described below.
- (6) Consists entirely of shares invested in the EQT Corporation common stock fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP as of December 31, 2023.
- (7) Consists entirely of shares available for future issuance under the 2005 DDCP as of December 31, 2023.

2005 Directors' Deferred Compensation Plan

The 2005 DDCP was adopted by the Compensation Committee, effective January 1, 2005. Neither the original adoption of the plan nor its amendments required approval by our shareholders. The plan allows non-employee directors to defer all or a portion of their directors' fees and retainers. Amounts deferred are payable on or following retirement from our Board of Directors unless an early payment is authorized after the director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers, the deferred stock units granted to directors on or after January 1, 2005 under the 2009 LTIP and the 2014 LTIP are administered under this plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by Items 404 and 407(a) of Regulation S-K with respect to related person transactions and director independence is incorporated herein by reference from our definitive proxy statement relating to the 2024 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2023.

Item 14. Principal Accountant Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference from our definitive proxy statement relating to the 2024 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2023.

PART IV

Item 15. Exhibits and Financial Statements Schedules

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EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2023

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Deductions Charged to Other Accounts	Deductions	Balance at End of Period
(Thousands)					
Valuation allowance for deferred tax assets:					
2023	\$ 365,140	\$ 12,549	\$ —	\$ (86,877)	\$ 290,812
2022	\$ 550,967	\$ 869	\$ —	\$ (186,696)	\$ 365,140
2021	\$ 529,992	\$ 38,556	\$ —	\$ (17,581)	\$ 550,967

See Note 7 to the Consolidated Financial Statements for a discussion of the change in valuation allowance.

All other schedules are omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedules.

3 Exhibits

Exhibit	Description	Method of Filing
2.01(a)**	Amended and Restated Purchase Agreement, dated December 23, 2022, among THQ Appalachia I, LLC, THQ-XcL Holdings I, LLC, the subsidiaries of the foregoing entities named on the signature pages thereto, EQT Production Company and EQT Corporation.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on December 27, 2022.
2.01(b)	First Amendment to Amended and Restated Purchase Agreement, dated April 21, 2023, among THQ Appalachia I, LLC, THQ-XcL Holdings I, LLC, the subsidiaries of the foregoing entities named on the signature pages thereto, EQT Production Company and EQT Corporation.	Incorporated herein by reference to Exhibit 2.2 to Form 8-K (#001-3551) filed on August 22, 2023.
2.01(c)	Second Amendment to Amended and Restated Purchase Agreement, dated August 21, 2023, among THQ Appalachia I, LLC, THQ-XcL Holdings I, LLC, the subsidiaries of the foregoing entities named on the signature pages thereto, EQT Production Company and EQT Corporation.	Incorporated herein by reference to Exhibit 2.3 to Form 8-K (#001-3551) filed on August 22, 2023.
3.01(a)	Restated Articles of Incorporation of EQT Corporation (as amended through November 13, 2017).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on November 14, 2017.
3.01(b)	Articles of Amendment to the Restated Articles of Incorporation of EQT Corporation (effective May 1, 2020).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on May 4, 2020.
3.01(c)	Articles of Amendment to the Restated Articles of Incorporation of EQT Corporation (effective July 23, 2020).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on July 23, 2020.
3.02	Amended and Restated Bylaws of EQT Corporation (as amended through December 12, 2023).	Incorporated herein by reference to Exhibit 3.2 to Form 8-K (#001-3551) filed on December 12, 2023.
4.01	Description of Capital Stock.	Incorporated herein by reference to Exhibit 4.01 to Form 10-K (#001-3551) for the year ended December 31, 2021.
4.02(a)	Indenture, dated July 1, 1996, between EQT Corporation (as successor to Equitable Resources, Inc.) and The Bank of New York (as successor to Bank of Montreal Trust Company), as trustee.	Incorporated herein by reference to Exhibit 4.01(a) to Form S-4 Registration Statement (#333-103178) filed on February 13, 2003.

Exhibit	Description	Method of Filing
4.02(b)	Resolutions adopted January 18 and July 18, 1996 by the Board of Directors of Equitable Resources, Inc. and Resolution adopted July 18, 1996 by the Executive Committee of the Board of Directors of Equitable Resources, Inc., establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996.	Incorporated herein by reference to Exhibit 4.01(j) to Form 10-K (#001-3551) for the year ended December 31, 1996.
4.02(c)	First Supplemental Indenture, dated June 30, 2008, between EQT Corporation, Equitable Resources, Inc., and The Bank of New York, as trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture.	Incorporated herein by reference to Exhibit 4.02(f) to Form 8-K (#001-3551) filed on July 1, 2008.
4.03(a)	Indenture, dated March 18, 2008, between EQT Corporation (as successor to Equitable Resources, Inc.) and The Bank of New York, as trustee.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on March 18, 2008.
4.03(b)	Cross-reference table for Indenture dated March 18, 2008 (listed as Exhibit 4.04(a) above) and the Trust Indenture Act of 1939, as amended.	Incorporated herein by reference to Exhibit 4.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
4.03(c)	Second Supplemental Indenture, dated June 30, 2008, between EQT Corporation, Equitable Resources, Inc. and The Bank of New York, as trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture.	Incorporated herein by reference to Exhibit 4.03(c) to Form 8-K (#001-3551) filed on July 1, 2008.
4.03(d)	Eighth Supplemental Indenture, dated October 4, 2017, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 3.900% Senior Notes due 2027 were issued.	Incorporated herein by reference to Exhibit 4.9 to Form 8-K (#001-3551) filed on October 4, 2017.
4.03(e)	Ninth Supplemental Indenture, dated January 21, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 6.125% Senior Notes due 2025 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on January 21, 2020.
4.03(f)	Tenth Supplemental Indenture, dated January 21, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 7.000% Senior Notes due 2030 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on January 21, 2020.
4.03(g)	Eleventh Supplemental Indenture, dated November 16, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.00% Senior Notes due 2029 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on November 16, 2020.
4.03(h)	Twelfth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 3.125% Senior Notes due 2026 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on May 18, 2021.
4.03(i)	Thirteenth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 3.625% Senior Notes due 2031 were issued.	Incorporated herein by reference to Exhibit 4.4 to Form 8-K (#001-3551) filed on May 18, 2021.
4.03(j)	Fifteenth Supplemental Indenture, dated October 4, 2022, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.700% Senior Notes due 2028 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on October 4, 2022.
4.03(k)	Sixteenth Supplemental Indenture, dated May 10, 2023, between EQT Corporation and The Bank of New York Mellon, as trustee, relating to EQT Corporation's 5.700% Senior Notes due 2028.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on May 11, 2023.
4.03(l)	Seventeenth Supplemental Indenture, dated January 19, 2024, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.750% Senior Notes due 2034 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on January 19, 2024.
9**	Voting Trustee Agreement, dated August 24, 2023, by and among U.S. Bank Trust Company, National Association, as voting trustee, Q-XcL Holdings I (VI) Investment Partners, LLC, Q-TH Appalachia (VI) Investment Partners, LLC and, for the limited purposes set forth therein, EQT Corporation.	Filed herewith as Exhibit 9.
10.01**	Third Amended and Restated Credit Agreement, dated June 28, 2022, among EQT Corporation, PNC Bank, National Association, as administrative agent, swing line lender and L/C issuer, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on June 28, 2022.

Exhibit	Description	Method of Filing
10.02(a)**	Credit Agreement, dated November 9, 2022, among EQT Corporation, PNC Bank, National Association, as administrative agent, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on November 9, 2022.
10.02(b)	First Amendment to Credit Agreement, dated December 23, 2022, among EQT Corporation, PNC Bank, National Association, as administrative agent, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on December 27, 2022.
10.02(c)	Second Amendment to Credit Agreement, dated April 25, 2023, among EQT Corporation, PNC Bank, National Association, as administrative agent, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on April 26, 2023.
10.02(d)	Third Amendment to Credit Agreement, dated as of January 16, 2024, by and among EQT Corporation, PNC Bank, National Association, as administrative agent, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on January 17, 2024.
10.03(a)**	Gas Gathering and Compression Agreement, dated February 26, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended March 31, 2020.
10.03(b)**	First Amendment to Gas Gathering and Compression Agreement, dated August 26, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended September 30, 2020.
10.03(c)**	Second Amendment to Gas Gathering and Compression Agreement, dated December 6, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.02(k) to Form 10-K (#001-3551) for the year ended December 31, 2021.
10.03(d)**	Third Amendment to Gas Gathering and Compression Agreement, dated December 21, 2021 and made effective January 1, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.02(l) to Form 10-K (#001-3551) for the year ended December 31, 2021.
10.03(e)**	Letter Agreement (Carnegie North Well Pad), dated December 14, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.03(q) to Form 10-K (#001-3551) for the year ended December 31, 2022.
10.03(f)**	Letter Agreement (Construction and Development), dated January 23, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.03(r) to Form 10-K (#001-3551) for the year ended December 31, 2022.
10.03(g)**	Fourth Amendment to Gas Gathering and Compression Agreement, dated January 23, 2023 and made effective December 31, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.03(s) to Form 10-K (#001-3551) for the year ended December 31, 2022.
10.03(h)**	Letter Agreement (Franklin Denny Gas), dated January 27, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.03(t) to Form 10-K (#001-3551) for the year ended December 31, 2022.
10.03(i)**	Letter Agreement (Trust North Well Pad), dated June 1, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC, EQM Gathering OpCo, LLC and Equitrans Water Services (PA), LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.02 to Form 10-Q (#001-3551) for the quarter ended June 30, 2023.
10.03(j)**	Letter Agreement, dated October 3, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.02(a) to Form 10-Q (#001-3551) for the quarter ended September 30, 2023.
10.03(k)**	Fifth Amendment to Gas Gathering and Compression Agreement, dated October 4, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-Q (#001-3551) for the quarter ended September 30, 2023.

Exhibit	Description	Method of Filing
10.03(l)**	Letter Agreement (Fuel Gas), dated October 5, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC, EQM Gathering Opco, LLC and Equitrans, L.P., relating to that certain Fifth Amendment to Gas Gathering and Compression Agreement, dated October 4, 2023.	Incorporated herein by reference to Exhibit 10.02(c) to Form 10-Q (#001-3551) for the quarter ended September 30, 2023.
10.03(m)**	Amended and Restated Letter Agreement, dated October 12, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Letter Agreement, dated October 3, 2023 and further that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.02(d) to Form 10-Q (#001-3551) for the quarter ended September 30, 2023.
10.04	Tax Matters Agreement, dated November 12, 2018, between EQT Corporation and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.3 to Form 8-K (#001-3551) filed on November 13, 2018.
10.05(a)	Registration Rights Agreement, dated July 21, 2021, among EQT Corporation and certain security holders thereof parties thereto, and Form of Lock-Up Agreement.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on July 22, 2021.
10.05(b)	Registration Rights Agreement, dated August 22, 2023, among EQT Corporation and certain security holders thereof party thereto, including THQ Appalachia I, LLC and THQ-XcL Holdings I, LLC.	Incorporated herein by reference to Exhibit 4.3 to Form S-3ASR (#333-274147) filed on August 22, 2023.
10.06(a)*	EQT Corporation 2009 Long-Term Incentive Plan (as amended and restated through July 11, 2012).	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q (#001-3551) for the quarter ended June 30, 2012.
10.06(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants).	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.06(c)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants).	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.07(a)*	EQT Corporation 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 1, 2014.
10.07(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2014.
10.07(c)*	Form of Restricted Stock Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2019 grants).	Incorporated herein by reference to Exhibit 10.02(aa) to Form 10-K (#001-3551) for the year ended December 31, 2018.
10.08(a)*	EQT Corporation 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#001-3551) filed on July 15, 2019.
10.08(b)*	Form of Restricted Stock Unit Award Agreement (Standard) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.08(c)*	Form of Incentive Performance Share Unit Program under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(d) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.08(d)*	Form of Participant Award Agreement under 2020 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.06(e) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.08(e)*	Form of Stock Appreciation Rights Award Agreement under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(f) to Form 10-K (#001-3551) for the year ended December 31, 2019.

Exhibit	Description	Method of Filing
10.08(f)*	Form of Participant Award Agreement (Stock Option) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.09(a)*	EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#333-237953) filed on May 1, 2020.
10.09(b)*	Amendment to EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated by reference to Exhibit 99.2 to Form S-8 (#333-264423) filed on April 21, 2022.
10.10(a)*	Form of Restricted Stock Unit Award Agreement (Standard).	Incorporated herein by reference to Exhibit 10.10(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.10(b)*	Form of Restricted Stock Unit Award Agreement (Non-Employee Directors).	Incorporated herein by reference to Exhibit 10.06(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.11*	Form of EQT Corporation Short-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 4, 2020.
10.12(a)*	Form of Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.12(b)*	Form of Participant Award Agreement under Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.13*	Form of Participant Award Agreement (Stock Option).	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.14*	EQT Corporation Executive Severance Plan and Form of Participation Notice.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 20, 2020.
10.15(a)*	2005 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014).	Incorporated herein by reference to Exhibit 10.09 to Form 10-K (#001-3551) for the year ended December 31, 2014.
10.15(b)*	Amendment to 2005 Directors' Deferred Compensation Plan (as amended October 2, 2018).	Incorporated herein by reference to Exhibit 10.5 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
10.16*	Form of Indemnification Agreement between EQT Corporation and executive officers and outside directors.	Incorporated herein by reference to Exhibit 10.18 to Form 10-K (#001-3551) for the year ended December 31, 2008.
10.17*	Separation and Release Agreement, dated November 13, 2017, among EQT Corporation, EQT RE, LLC and Daniel J. Rice IV.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on November 17, 2017.
10.18(a)*	Offer Letter, dated December 18, 2019, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.28(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.18(b)*	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated January 3, 2020, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.28(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.18(c)*	Transition Agreement and General Release, dated February 11, 2023, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on February 13, 2023.

Exhibit	Description	Method of Filing
10.19*	Offer Letter, dated January 6, 2020, between EQT Corporation and William E. Jordan.	Incorporated herein by reference to Exhibit 10.29(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(a)*	Offer Letter, dated July 18, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(b)*	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated August 5, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(c)*	Relocation Expense Reimbursement Agreement, dated July 24, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.21*	Offer Letter, dated July 16, 2019, between EQT Corporation and Lesley Evancho.	Incorporated herein by reference to Exhibit 10.31(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
21	Schedule of Subsidiaries.	Filed herewith as Exhibit 21.
23.01	Consent of Independent Registered Public Accounting Firm.	Filed herewith as Exhibit 23.01.
23.02	Consent of Netherland, Sewell & Associates, Inc.	Filed herewith as Exhibit 23.02.
31.01	Rule 13(a)-14(a) Certification of Principal Executive Officer.	Filed herewith as Exhibit 31.01.
31.02	Rule 13(a)-14(a) Certification of Principal Financial Officer.	Filed herewith as Exhibit 31.02.
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer.	Furnished herewith as Exhibit 32.
97	EQT Corporation Clawback Policy.	Filed herewith as Exhibit 97.
99	Independent Petroleum Engineers' Audit Report.	Incorporated herein by reference to Exhibit 99.2 to Form 8-K (#001-3551) filed on January 17, 2024.
101	Interactive Data File.	Filed herewith as Exhibit 101.
104	Cover Page Interactive Data File.	Formatted as Inline XBRL and contained in Exhibit 101.

*Management contract or compensatory arrangement.

**Certain schedules and similar attachments to this exhibit have been omitted pursuant to Item 601(a)(5) and/or Item 601(b)(10)(iv), as applicable, of Regulation S-K. EQT Corporation agrees to furnish an unredacted, supplemental copy (including any omitted schedule or attachment) to the SEC upon request. Redactions and omissions are designated with brackets containing asterisks.

Certain instruments evidencing long-term debt have not been filed as exhibits hereto because none of the debt authorized under any such instruments exceeds 10% of the Company's total assets. EQT Corporation agrees to furnish to the SEC, upon request, a copy of any such instruments.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

EQT CORPORATION

By:

/s/ Toby Z. Rice

Toby Z. Rice

President and Chief Executive Officer

February 14, 2024

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.

<u>/s/ TOBY Z. RICE</u> Toby Z. Rice (Principal Executive Officer)	President, Chief Executive Officer and Director	February 14, 2024
<u>/s/ JEREMY T. KNOP</u> Jeremy T. Knop (Principal Financial Officer)	Chief Financial Officer	February 14, 2024
<u>/s/ TODD M. JAMES</u> Todd M. James (Principal Accounting Officer)	Chief Accounting Officer	February 14, 2024
<u>/s/ LYDIA I. BEEBE</u> Lydia I. Beebe	Chair	February 14, 2024
<u>/s/ LEE M. CANAAN</u> Lee M. Canaan	Director	February 14, 2024
<u>/s/ JANET L. CARRIG</u> Janet L. Carrig	Director	February 14, 2024
<u>/s/ FRANK C. HU</u> Frank C. Hu	Director	February 14, 2024
<u>/s/ KATHRYN J. JACKSON</u> Kathryn J. Jackson	Director	February 14, 2024
<u>/s/ JOHN F. MCCARTNEY</u> John F. McCartney	Director	February 14, 2024
<u>/s/ JAMES T. MCMANUS II</u> James T. McManus II	Director	February 14, 2024
<u>/s/ ANITA M. POWERS</u> Anita M. Powers	Director	February 14, 2024
<u>/s/ DANIEL J. RICE IV</u> Daniel J. Rice IV	Director	February 14, 2024
<u>/s/ HALLIE A. VANDERHIDER</u> Hallie A. Vanderhider	Director	February 14, 2024

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