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, 2024

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	**25-0464690**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
625 Liberty Avenue, Suite 1700	
Pittsburgh, Pennsylvania	**15222**
(Address of principal executive offices)	(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	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒
The aggregate market value of common stock, no par value, held by non-affiliates of the registrant as of June 28, 2024: $16.2 billion

The number of shares of common stock, no par value, of the registrant outstanding (in thousands) as of February 14, 2025: 597,441

DOCUMENTS INCORPORATED BY REFERENCE

EQT Corporation's definitive proxy statement relating to its 2025 annual meeting of shareholders will be filed with the Securities and Exchange Commission within 120 days after the end of EQT Corporation's fiscal year ended December 31, 2024 and is incorporated by reference into Part III of this Annual Report on Form 10-K to the extent described therein.

TABLE OF CONTENTS

Glossary of Commonly Used Terms, Abbreviations and Measurements

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

delivery point – the point where gas is delivered into a downstream gathering system or transmission pipeline.

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.

minimum volume commitment (MVC) – contract for gathering services that obligate the customer to pay for a fixed amount of volume daily, monthly, annually or over the life of the contract.

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.

throughput – the volume of natural gas transported through a pipeline, plant, terminal or other facility.

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 gas – the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility.

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 Production, Midstream and Processing Operations.** As a natural gas producer and an operator of gathering and 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 to which most operators in our industry have at least some exposure.

- **Financial and Market Risks.** Given that our primary product and source of revenue is the gathering, transmission and 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, increased prices of raw materials such as iron, sand and water, 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 natural gas and NGLs 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 the majority of our assets, physical infrastructure and midstream customers are also located in the Appalachian Basin, making us vulnerable to risks associated with operating primarily in one major geographic 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 projects; 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 vertically integrated natural gas company with production, gathering and transmission operations focused in the Appalachian Basin. As of December 31, 2024, we had 26.3 Tcfe of proved natural gas, NGLs and oil reserves across approximately 2.1 million gross acres and approximately 2,925 miles of pipeline infrastructure. In addition, we operate and hold an investment in the Mountain Valley Pipeline (the MVP), a 303-mile long pipeline that spans from Wetzel County, West Virginia to Pittsylvania County, Virginia.

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 and deliver environmentally responsible, reliable and affordable energy.

Our business strategy is to be the lowest-cost producer of natural gas. The durability of this strategy relies on our substantial inventory of core drilling locations, our vast midstream infrastructure spanning the Appalachian Basin, our investment grade balance sheet, the low emissions profile of our operations and our best-in-class team and culture. As the only large-scale, integrated natural gas producer in the United States, we are situated to endure and excel during times of market volatility. In periods of low commodity prices, our integrated business model is designed to produce durable free cash flow due to the annuity-like nature of our midstream assets. In periods of high commodity prices, our low-cost structure permits lower levels of financial hedging, thus providing increased exposure to higher natural gas prices. Our peer-leading drilling inventory coupled with our midstream ownership and operatorship also positions us to provide production growth to serve growing demand from the power and LNG markets.

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 and provides the ability to continuously meet completions supply needs and the use of environmentally friendly technologies such as electric hydraulic fracturing powered by natural gas. Our operational strategy is further enhanced by our robust midstream pipelines and services, enabling us to keep our development costs low and limiting our need to hedge our future production, providing both downside protection and better exposure to natural gas price increases in the face of a volatile commodity market.

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 enables us to generate durable free cash flow and correspondingly, we have implemented a robust capital allocation strategy directed at responsibly developing our assets and positioning us for organic growth, while also returning capital to our shareholders through a combination of debt retirements, a base dividend and opportunistic share repurchases. We are also focused on maintaining and strengthening our investment grade credit metrics, which improve our access to reliable, low-cost capital throughout market cycles. Furthermore, we believe the benefits of our operating model can be enhanced through select strategic transactions, and, as such, part of our strategy includes creating value through mergers and acquisitions, divestitures, joint ventures and similar business transactions as well as by 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, the size and contiguity of our asset base, and our robust midstream pipeline network, uniquely position us to execute on a multi-decade 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.

2024 and Recent Highlights

- Generated $2.8 billion of net cash provided by operating activities.
- Completed the Equitrans Midstream Merger (defined in Note 6 to the Consolidated Financial Statements).
- Completed the First NEPA Non-Operated Asset Divestiture (defined in Note 7 to the Consolidated Financial Statements) in May 2024 and the Second NEPA Non-Operated Asset Divestiture (defined in Note 7 to the Consolidated Financial Statements) in December 2024.
- Completed the Midstream Joint Venture Transaction (defined in Note 8 to the Consolidated Financial Statements).
- Retired $4.3 billion aggregate principal of senior notes and term loans outstanding under the Term Loan Facility (defined in Note 10 to the Consolidated Financial Statements).
- Paid $327 million in aggregate dividends to shareholders.

Outlook

In 2025, we expect to spend approximately $2.3 billion to $2.5 billion on total capital expenditures. We expect to allocate the total planned capital expenditures as follows: approximately $1,445 million to $1,555 million to fund reserve development, approximately $160 million to $180 million to fund land and lease acquisitions, approximately $80 million to $90 million to fund other production infrastructure, approximately $360 million to $390 million to fund gathering infrastructure, approximately $50 million to $60 million to fund transmission infrastructure and approximately $205 million to $225 million towards capitalized interest, capitalized overhead and other. Of the total planned capital expenditures, we expect to allocate approximately $350 million to $380 million to strategic growth projects composed of approximately $85 million to $95 million for water infrastructure within reserve development, approximately $130 million to $140 million for growth projects within gathering infrastructure and approximately $135 million to $145 million for in-fill leasing within land and lease acquisitions. In 2025, we expect our sales volume to be 2,175 Bcfe to 2,275 Bcfe.

We are committed to maintaining investment grade credit metrics. In 2024, we published a leverage and debt retirement strategy with the goal of reducing our debt to $7.5 billion by the end of 2025, and, in 2025, we published an update to our leverage and debt retirement strategy with the long-term goal of reducing our debt to $5.0 billion, subject to the overall performance of the commodity markets (our Debt Retirement Plan). 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 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, which are also largely dependent on natural gas prices. 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 and midstream infrastructure 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

Prior to the completion of the Equitrans Midstream Merger, we reported our results of operations as a single consolidated segment. Thereafter, and as a result thereof, we adjusted our internal reporting structure and our chief operating decision maker changed the manner in which he measures financial performance and allocates resources to incorporate the gathering and transmission assets we acquired in the Equitrans Midstream Merger. Hence, our operations expanded to comprise three discrete segments reflective of our three lines of business of Production, Gathering and Transmission. Accordingly, the manner in which we report our operations has been changed retrospectively, with certain prior period amounts recast between our Production segment and Gathering segment. See Note 2 to the Consolidated Financial Statements as well as Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of our reportable segments.

Substantially all of our assets and operations are located in the Appalachian Basin.

Composition of Operating Revenues

The following table summarizes the composition of our operating revenues by business segment.

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Operating revenues:			
Production (a)	$ 5,009,833	$ 6,896,358	$ 7,484,063
Gathering (b)	749,700	161,395	96,947
Transmission (b)	218,293	—	—
Total Segment	5,977,826	7,057,753	7,581,010
Intersegment eliminations and other (c)	(704,517)	(148,830)	(83,321)
EQT Corporation	$ 5,273,309	$ 6,908,923	$ 7,497,689

(a) Primarily sales of natural gas, NGLs and oil and, for 2023 and 2022, gain (loss) on derivatives.
(b) Primarily pipeline revenues.
(c) Primarily elimination of intercompany transactions between our Production segment and our Gathering or Transmission segments for the transportation of our natural gas.

Production Segment Assets and Operations

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, 2024		
	Natural Gas	NGLs and Oil	Total
	(Bcf)	(MMbbl)	(Bcfe)
Proved developed reserves	17,440	227	18,805
Proved undeveloped reserves	7,105	59	7,460
Total proved reserves	24,545	286	26,265

90% of our total proved developed reserves, 98% of our total proved undeveloped reserves and 92% of our total proved reserves are located in the Marcellus Shale.

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, 2024			
	Pennsylvania	West Virginia	Ohio	Total
	(Bcfe)			
Proved developed reserves	12,093	5,850	862	18,805
Proved undeveloped reserves	3,741	3,677	42	7,460
Total proved reserves	15,834	9,527	904	26,265
Gross proved undeveloped drilling locations	178	181	3	362
Net proved undeveloped drilling locations	150	158	3	311

Our 2024 total proved reserves decreased by 1,332 Bcfe, or 4.8%, compared to 2023 due to production of 2,228 Bcfe, negative revisions of previous estimates of 1,080 Bcfe and decreases from the NEPA Non-Operated Asset Divestitures of 1,563 Bcfe, partly offset by extensions, discoveries and other additions of 3,126 Bcfe and acquisitions from the First NEPA Non-Operated Asset Divestiture of 413 Bcfe.

Our 2024 proved undeveloped reserves decreased by 579 Bcfe, or 7.2%, compared to 2023. The following table provides a rollforward of our proved undeveloped reserves.

	Proved Undeveloped Reserves
	(Bcfe)
Balance at January 1, 2024	8,039
Conversions into proved developed reserves	(2,637)
Divestiture (a)	(188)
Revision of previous estimates (b)	(823)
Extensions, discoveries and other additions (c)	3,069
Balance at December 31, 2024	7,460

(a) Proved undeveloped non-operated assets divested in the NEPA Non-Operated Asset Divestitures. See Note 7 to the Consolidated Financial Statements.

(b) Composed of (i) negative revisions of 925 Bcfe related to proved undeveloped locations that we no longer expect to develop as proved reserves within five years of initial booking primarily as a result of development schedule changes, (ii) negative revisions of 87 Bcfe primarily related to revisions to lateral lengths and type curves, partly offset by (iii) positive revisions of 189 Bcfe due primarily to changes in ownership interests.

(c) Composed of (i) 2,912 Bcfe from proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2024 reserve development that expanded the number of our proven locations and additions to our five-year drilling plan and (ii) positive revisions of 157 Bcfe from the extension of lateral lengths of proved undeveloped reserves.

As of December 31, 2024, 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 presents estimated future net cash flows from proved reserves (excluding cash flows from open derivative contracts), the present value of such net cash flows discounted at a rate of 10% (PV-10) and the prices used in estimating such net cash flows. Our reserve estimates do not include any probable or possible reserves.

	Years Ended December 31,		
	2024	2023	2022
	(Millions, unless otherwise noted)		
Future net cash flow	$ 17,094	$ 19,031	$ 87,612
Standardized Measure (a)	7,999	9,262	40,065
PV-10 (a)	9,844	11,520	51,512
Prices, including regional adjustments:			
Natural gas price ($/Mcf)	$ 1.468	$ 1.700	$ 5.543
NGLs price ($/Bbl)	29.28	28.44	38.66
Oil price ($/Bbl)	59.45	63.86	76.83

(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 comparable financial measure calculated in accordance with GAAP. PV-10 differs from the Standardized Measure in that PV-10 excludes the effects of income taxes on future net revenues. We believe the presentation of PV-10 is relevant and useful to investors because it provides the discounted future net cash flows attributable to our proved reserves without regard to any of our specific income tax characteristics and is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Investors may use PV-10 as a basis for comparing the relative size and value of our proved reserves to that of other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure. 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 17 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.

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

	Years Ended December 31,		
	2024	2023	2022
	(Millions)		
Standardized Measure	$ 7,999	$ 9,262	$ 40,065
Estimated discounted income taxes on future net revenues	1,845	2,258	11,447
PV-10	$ 9,844	$ 11,520	$ 51,512

If the prices we used to calculate the Standardized Measure instead reflected five-year strip pricing as of December 31, 2024 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 26,742 Bcfe, the Standardized Measure of our proved reserves would be $22,020 million, the discounted future net cash flows before taxes would be $26,712 million and the average realized product prices weighted by production over the remaining lives of the properties would be $3.016 per Mcf of gas, $24.49 per barrel of NGLs and $47.54 per barrel of oil.

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 3,600 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.

Production Acreage

The majority of our production 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 37% of our total gross acres is developed. We retain deep drilling rights on the majority of our production acreage.

The following table summarizes our production acreage disaggregated by state.

	December 31, 2024			
	Pennsylvania	**West Virginia**	**Ohio**	**Total**
Total gross productive acreage	440,850	264,583	73,247	778,680
Total gross undeveloped acreage	738,302	433,912	126,215	1,298,429
Total gross acreage	1,179,152	698,495	199,462	2,077,109
Total net productive acreage	434,088	225,617	62,931	722,636
Total net undeveloped acreage	726,978	370,008	108,438	1,205,424
Total net acreage	1,161,066	595,625	171,369	1,928,060
Average net revenue interest of proved developed reserves	80.6 %	77.2 %	43.4 %	76.5 %

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, 17,345, 26,478 and 29,342 of our net undeveloped production acreage as of December 31, 2024 will expire in the years ending December 31, 2025, 2026 and 2027, respectively.

Productive and In-Process 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, 2024.

	December 31, 2024			
	Pennsylvania	West Virginia	Ohio	Total
Productive wells:				
Total gross productive wells (a)	3,060	1,141	412	4,613
Total net productive wells	2,853	1,077	212	4,142
In-process wells:				
Total gross in-process wells	146	147	13	306
Total net in-process wells	115	139	—	254

(a) Of our total gross productive wells, there are 744 gross conventional wells in Pennsylvania and 6 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, 2024, 2023 and 2022, 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, 2024	76	44	2	122
Year Ended December 31, 2023	91	47	2	140
Year Ended December 31, 2022	55	26	2	83

The following table summarizes the gross and net wells on which we commenced drilling operations (spud) in 2024.

	Pennsylvania	West Virginia	Ohio	Total
Gross wells spud	64	35	11	110
Net wells spud	53	35	—	88

Production, Sales, Customers and Price

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

	Pennsylvania	West Virginia	Ohio	Total
	(MMcfe)			
Year Ended December 31, 2024	1,418,812	713,267	96,080	2,228,159
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

For the years ended December 31, 2024, 2023 and 2022, lease operating expenses (LOE) per Mcfe were $0.09, $0.07 and $0.08, respectively. For more information on our Production segment's operating expenses, refer to "Business Segment Results of Operations – PRODUCTION" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 4 to the Consolidated Financial Statements.

NGLs Sales. We primarily sell NGLs recovered from our natural gas production. We contract with our Gathering segment (which owns and operates a processing facility), MarkWest Energy Partners, L.P., Williams Ohio Valley Midstream LLC and Blue Racer Midstream to process 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.

Natural Gas and NGLs 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, East Coast corridor and Northeast United States and Canada. As of December 31, 2024, approximately 44% 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 4.9 Bcf per day of firm pipeline takeaway capacity, including 1.29 Bcf per day of firm pipeline takeaway capacity on the MVP that we have contracted through June 30, 2044. In addition, we are committed to an additional 0.55 Bcf per day of firm pipeline takeaway capacity on MVP Southgate once in service. We have access to approximately 1.1 Bcf per day of firm processing capacity, including 0.2 Bcf per day of firm processing capacity on our owned processing facility. These firm transportation and processing agreements may require minimum volume delivery commitments, which we expect to principally fulfill with production from existing reserves.

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.

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,		
	2024	**2023**	**2022**
Natural gas ($/Mcf):			
Average sales price, excluding cash settled derivatives	$ 2.02	$ 2.37	$ 6.22
Average sales price, including cash settled derivatives	2.59	2.68	3.00
NGLs, excluding ethane ($/Bbl):			
Average sales price, excluding cash settled derivatives	$ 39.13	$ 36.39	$ 53.26
Average sales price, including cash settled derivatives	38.83	35.12	49.35
Ethane ($/Bbl):			
Average sales price	$ 6.03	$ 6.00	$ 14.20
Oil ($/Bbl):			
Average sales price	$ 58.67	$ 59.93	$ 77.06
Natural gas, NGLs and oil ($/Mcfe):			
Average sales price, excluding cash settled derivatives	$ 2.21	$ 2.50	$ 6.24
Average sales price, including cash settled derivatives	2.74	2.79	3.17

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."

Delivery Commitments

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, 2024.

	Natural Gas	NGLs
	(Bcf)	**(Mbbl)**
Years Ending December 31,		
2025	1,333	12,869
2026	572	5,429
2027	520	3,808
2028	404	3,660
2029	349	3,650
Thereafter	1,811	27,380

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 capacity on the MVP for up to ten years beginning in 2027. The firm sales agreements are subject to currently unsatisfied conditions related to the in-service date of the Transco Southeast Supply Enhancement project; therefore, their impact has been excluded from the schedule of total gross commitments in the table above.

Gathering Segment Assets and Operations

Gathering System

As of December 31, 2024, our gathering system included approximately 1,975 miles of gathering lines (of which approximately 1,260 miles were high-pressure gathering lines), 179 compression units with an aggregate compression of approximately 623,000 horsepower and multiple interconnect points to our transmission and storage system and to other interstate pipelines. In addition, we own a processing facility with capacity of 0.2 Bcf per day.

Gathering Customers

Our Gathering segment has gathering agreements with our Production segment and third parties. Certain of our Gathering segment's agreements provide us the right to elect to gather all natural gas produced from wells located in specified dedicated acreage. For the year ended December 31, 2024, our Production segment accounted for approximately 71% of our gathering system's throughput and approximately 80% of our Gathering segment's operating revenues.

As of December 31, 2024, our gathering system had total contracted firm reservation capacity, including contracted MVCs, of approximately 7.5 Bcf per day. Including future capacity expected from expansion projects that are not yet fully constructed or not yet fully in service for which we have executed firm service contracts, our gathering system had total contracted firm reservation capacity, including contracted MVCs, of approximately 8.6 Bcf per day as of December 31, 2024.

Based on total projected contractual revenues, our firm gathering contracts with third parties had a weighted average remaining term of approximately 10 years as of December 31, 2024. In addition, based on total projected contractual revenues, our firm gathering contracts with our Production segment had a weighted average remaining term of approximately 14 years as of December 31, 2024.

Generally, our Gathering segment does not take title to the natural gas gathered by its assets, but it retains a percentage of wellhead gas receipts to recover natural gas used to fuel its compressor stations and meet other requirements of its gathering system.

Transmission Segment Assets and Operations

Transmission System

As of December 31, 2024, our transmission and storage system included approximately 950 miles of FERC-regulated, interstate pipelines with total throughput capacity of approximately 5.0 Bcf per day, 44 compression units with an aggregate compression of approximately 175,000 horsepower and 8 interconnect points to other interstate pipelines and multiple local distribution companies. As of December 31, 2024, our transmission and storage system included 18 natural gas storage reservoirs with a peak withdrawal capacity of approximately 800 MMcf per day and a working gas capacity of approximately 43 Bcf.

Transmission Customers

Our Transmission segment has transmission and storage agreements with our Production segment and third parties. Third-party transmission and storage customers include local distribution companies, other producers, marketers and commercial and industrial users. For the year ended December 31, 2024, our Production segment accounted for approximately 64% of our transmission assets' throughput and approximately 59% of our Transmission segment's operating revenues.

Including future capacity expected from expansion projects that are not yet fully constructed or not yet fully in service for which we have executed firm service contracts, our transmission and storage system had total firm capacity subscribed under transmission contracts of approximately 5.4 Bcf per day and total firm capacity subscribed under storage contracts of 38.4 Bcf as of December 31, 2024.

Based on total projected contractual revenues, our firm transmission and storage contracts with third parties had a weighted average remaining term of approximately 11 years as of December 31, 2024. In addition, based on total projected contractual revenues, our firm transmission and storage contracts with our Production segment had a weighted average remaining term of approximately 13 years as of December 31, 2024.

Generally, our Transmission segment does not take title to the natural gas transported or stored by its assets but does retain a percentage of the gas receipts to recover natural gas used to fuel its compressor stations and meet other requirements of its transmission and storage system.

As of December 31, 2024, approximately 99% of our Transmission segment's contracted firm transmission capacity was subscribed under negotiated rate agreements. As of December 31, 2024, our Transmission segment had minimal contracted firm transmission capacity subscribed at discounted rates and recourse rates. See also "Regulation" below and Part I, "Item 1A. Risk Factors – A substantial majority of the services we provide on our transmission and storage systems are subject to long-term, fixed-price 'negotiated rate' contracts that are subject to limited or no adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts, we could be unable to achieve the expected investment return under such contracts, and/or our business, financial condition, results of operations, and cash flows could be adversely affected." for additional information.

The MVP and MVP Southgate

We operate and hold an equity method investment in the MVP, a 303-mile long, 42-inch diameter natural gas interstate pipeline with a total capacity of 2.0 Bcf per day that spans from the Company's transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia and has 3 interconnect points to other interstate pipelines. Based on total projected contractual revenues, the MVP's firm transmission contracts had a weighted average remaining term of approximately 19.5 years as of December 31, 2024.

In addition, we hold an equity method investment in MVP Southgate, a contemplated 31-mile, 30-inch diameter natural gas interstate pipeline with a targeted capacity of 0.55 Bcf per day that would extend from the terminus of the MVP in Pittsylvania County, Virginia to new delivery points in Rockingham County, North Carolina. MVP Southgate is estimated to have a total cost of approximately $370 million to $430 million, excluding allowance for funds used during construction (AFUDC) and certain costs incurred for purposes of the originally certificated project (see Note 11 to the Consolidated Financial Statements for further details), of which we will fund our proportionate share through capital contributions to the MVP Joint Venture (defined in Note 11 to the Consolidated Financial Statements).

Seasonality

Generally, but not always, the demand for natural gas (including the demand for its gathering, transmission or storage) 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.

Competitors for our natural gas gathering business include companies that own major natural gas pipelines, independent gas gatherers and integrated energy companies, including natural gas producers that develop or acquire their own gathering system. When compared to us, some of our competitors have operations in multiple natural gas producing basins, greater capital resources and access to, or control of, larger natural gas supplies.

Competition for our natural gas transmission and storage business is based primarily on rates, customer commitment levels, timing, performance, commercial terms, reliability, service levels, location, reputation and fuel efficiencies. Our principal competitors include companies that own major natural gas pipelines in the Appalachian Basin. In addition, we compete with companies that are building high-pressure gathering facilities that are able to transport natural gas to interstate pipelines without being subject to FERC jurisdiction.

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 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 U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA); 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 us. 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 (NGPA). 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 approximately $1.6 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 exceed a specific volume and 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 production activities.

Our FERC-regulated operations are pursuant to tariffs approved by the FERC that establish rates (other than market-based rate authority), cost recovery mechanisms and terms and conditions of service to customers. Generally, the FERC's authority extends to rates and charges for: our natural gas transmission and storage services; certification and construction of new interstate transmission and storage facilities; abandonment of interstate transmission and storage services and facilities; maintenance of accounts and records; relationships between pipelines and certain affiliates; terms and conditions of services and service contracts with customers; depreciation and amortization policies; acquisitions and dispositions of interstate transmission and storage facilities; and initiation and discontinuation of interstate transmission and storage services.

Unless market-based rates have been approved by the FERC, the maximum applicable recourse rates and terms and conditions for service are set forth in the pipeline's FERC-approved tariff. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of providing service, including the recovery of a return on the pipeline's actual and prudent historical investment costs. Key determinants in the ratemaking process include the depreciated capital costs of the facilities, the costs of providing service, the allowed rate of return and income tax allowance, as well as volume throughput and contractual capacity commitment assumptions.

Interstate pipelines may not charge rates or impose terms and conditions of service that, upon review by the FERC, are found to be unjust or unreasonable, unduly discriminatory or preferential. Rate design and the allocation of costs also can affect a pipeline's profitability. While the ratemaking process establishes the maximum rate that can be charged, interstate pipelines, such as our transmission and storage system, are permitted to discount their firm and interruptible rates without further FERC authorization down to a specified minimum level, provided they do not unduly discriminate. In addition, pipelines are allowed to negotiate different rates with their customers, under certain circumstances. Changes to rates or terms and conditions of service, and contracts can be proposed by a pipeline company under Section 4 of the NGA, or the existing interstate transmission and storage rates, terms and conditions of service and/or contracts may be challenged by a complaint filed by interested persons including customers, state agencies or the FERC under Section 5 of the NGA. Rate increases proposed by a pipeline may be allowed to become effective subject to refund and/or a period of suspension, while rates or terms and conditions of service that are the subject of a complaint under Section 5 of the NGA are subject to prospective change by the FERC. Rate increases proposed by a regulated interstate pipeline may be challenged and such increases may ultimately be rejected by the FERC.

Our interstate pipeline may also use negotiated rates that could involve rates above or below the recourse rate or rates that are subject to a different rate structure than the rates specified in our interstate pipeline tariffs, provided that the affected customers are willing to agree to such rates and that the FERC has approved the negotiated rate agreement. A prerequisite for allowing the negotiated rates is that negotiated rate customers must have had the option to take service under the pipeline's recourse rates. As of December 31, 2024, approximately 99% of our system's contracted firm transmission capacity was subscribed under negotiated rate agreements under its tariff. Some negotiated rate transactions are designed to fix the negotiated rate for the term of the firm transportation agreement and the fixed rate is generally not subject to adjustment for increased or decreased costs occurring during the contract term.

The FERC's regulations also extend to the terms and conditions set forth in agreements for transmission and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with and accepted by the FERC. In the event that the FERC finds that an agreement is materially non-conforming, in whole or in part, it could reject, or require us to seek modification of, the agreement, or alternatively require us to modify its tariff so that the non-conforming provisions are generally available to all customers or class of customers.

The FERC's jurisdiction also extends to the certification and construction of new interstate transmission and storage facilities, including, but not limited to, acquisitions, facility replacements and upgrades, expansions, and abandonment of facilities and services. Prior to commencing construction of new or existing interstate transmission and storage facilities, an interstate pipeline must obtain (except in certain circumstances, such as where the activity is permitted under the FERC's regulations or is authorized under the operator’s existing blanket certificate issued by the FERC) a certificate authorizing the construction, or file to amend its existing certificate, from the FERC.

In April 2018, the FERC issued a Notice of Inquiry (2018 Notice of Inquiry) seeking information regarding whether, and if so how, it should revise its approach under its currently effective policy statement on the certification of new natural gas transportation facilities (Certificate Policy Statement). The formal comment period in this proceeding closed in June 2018. In February 2021, the FERC issued another Notice of Inquiry in the same proceeding that modified and expanded the inquiry and renewed its request for public comment (together with the 2018 Notice of Inquiry, the Certificate Policy Statement NOI). The formal comment period closed in May 2021. In February 2022, the FERC issued an Updated Certificate Policy Statement and an interim greenhouse gas (GHG) policy. In March 2022, the FERC issued an order suspending the effectiveness of the Updated Certificate Policy Statement and the interim GHG policy. In January 2025, the FERC terminated the interim GHG policy proceeding, stating that GHG-related considerations are better considered on a case-by-case basis in individual proceedings; the FERC has taken no further action to date on the Updated Certificate Policy Statement. There is a possibility that Congress could pass legislation revising the NGA or other statutes that may impact our existing facilities and operations or the ability to construct new facilities. Potential areas of revision include, but are not limited to, (i) amending Section 5 of the NGA to allow the FERC to require a pipeline to make refunds from the date that a NGA Section 5 complaint was filed with the FERC if rates are later found to be unjust and unreasonable; (ii) amending Section 7 of the NGA affecting the ability of companies to exercise eminent domain; and (iii) amending Section 19(b) of the NGA to provide the FERC additional time to act on requests for rehearing.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC under the NGA. While the FERC does not generally regulate the rates and terms of service over facilities determined to be performing a natural gas gathering function, it has traditionally regulated rates charged by interstate pipelines for gathering services performed on the pipeline's own gathering facilities when those gathering services are performed in connection with jurisdictional interstate transmission services. We believe that our high-pressure gathering systems meet the traditional tests the FERC has used to establish a pipeline's status as an exempt gatherer not subject to regulation as a jurisdictional natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is often the subject of litigation in the industry, so the classification and regulation of these systems are subject to change based on future determinations by the FERC, the courts or Congress.

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 more than $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. In July 2024, the U.S. Court of Appeals for the District of Columbia Circuit found that the FERC did not adhere to notice-and-comment procedures in its January 2022 rehearing order. The court vacated the rehearing order. In October 2024, the FERC issued a supplemental notice of proposed rulemaking, which would amend the initial index prospectively by adopting a revised index level for the remainder of the five-year period that began on July 1, 2021.

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. Roughly half of the states and other plaintiffs are challenging the September 2023 rule, and the EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. 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. The Court rejected the EPA and the Corps' assertion that groundwater should be totally excluded from the CWA. In November 2023, the EPA issued draft guidance describing the information that should be used to determine which discharges through groundwater may require a permit. However, in January 2025, President Trump issued executive orders directing (i) the EPA and the Corps to identify planned or potential actions that could be subject to emergency treatment under Section 404 of the CWA and (ii) the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions, including all existing regulations and guidance documents, that are unduly burdensome on the identification, development, or use of domestic energy resources. Accordingly, future implementation and enforcement of these rules and policies is uncertain at this time. 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.

The *Sackett* decision may also have effects on the implementation of Water Quality Certifications (WQCs) under Section 401 of the CWA. Section 401 requires that any activity that may result in a discharge to WOTUS must first receive a Section 401 WQC before a federal agency may issue a permit for that activity. A WQC is typically issued by the state where the discharge originates, or by the EPA itself in areas where a state or tribe does not have authority. In 2020, the EPA finalized a series of changes to the CWA regulations governing the WQC process, largely curtailing state and tribal authority over WQCs. In September 2023, the EPA published a final rule that restores state and tribal authority to review requests for WQCs and imposes additional requirements on the WQC process. The final rule took effect on November 27, 2023, but has been challenged by states and regulated entities in ongoing litigation to enjoin its enforcement. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Accordingly, future implementation and enforcement of the final rule is uncertain. If certain elements of the final rule remain in effect, we could face increased costs and delays with respect to obtaining permits for pipeline crossings and other activities in jurisdictional and non-jurisdictional waters.

Nationwide Permits (NWPs) are issued by the Corps under the CWA and the Rivers and Harbors Act of 1899 and act as a type of general permit to minimize delays and paperwork for certain activities and discharges in federal jurisdictional waters and wetlands. NWPs are typically reviewed and reissued (or modified) every five years. One such permit, NWP 12, authorizes certain "Oil or Natural Gas Pipeline Activities" and was most recently modified and reissued in January 2021. In March 2022, the Corps initiated an early review of NWP 12 to determine whether any future actions may be appropriate to modify NWP 12 prior to its expiration in 2026. The Corps solicited public and stakeholder comments through public meetings held in May 2022, but has not provided any additional updates on the status of its review. However, in January 2025, President Trump issued an executive order instructing the Corps to use emergency authorities and NWPs to grant approvals for energy projects under Section 404 of the CWA. As a result, any future revisions to NWPs, including NWP 12, are uncertain at this time. To the extent future revisions to NWP 12 or litigation relating to such revisions modify its provisions with respect to oil and natural gas pipeline activities, we could face increased costs and delays with respect to obtaining permits for certain activities in jurisdictional waters, including wetlands.

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 in Subpart OOOOa, 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, among other requirements. 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 until March 2026 to develop and submit their plans for reducing methane from existing sources. Subpart OOOOc then provides until 2029 for existing sources to comply. Fines and penalties for violation of the final rule could be substantial. The final rule is subject to ongoing litigation but remains in effect. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Consequently, future implementation and enforcement of the final rule remains uncertain at this time.

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.

National Environmental Policy Act (NEPA). NEPA establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action with the potential to significantly impact the environment requires review under NEPA. Some activities are subject to robust NEPA review, which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. Other activities are covered under a categorical exclusion, which results in a shorter NEPA review process. In April 2022, the White House Council on Environmental Quality (CEQ) finalized the first of two planned rules to undo changes to NEPA enacted in 2020 under the Trump Administration. The Phase I final rule generally restores certain regulatory provisions that were in effect prior to the 2020 rule, affecting the assessment of projects ranging from oil and gas leasing to development on public and Native American lands. Additionally, in September 2023, the Biden Administration announced that federal agencies will be directed to consider the social cost of carbon in agency budgeting, procurement and other agency decisions, including in environmental reviews conducted pursuant to NEPA, where appropriate. In May 2024, CEQ finalized the Phase II rule, which generally restores certain mitigation language from the pre-2020 version of the NEPA regulations, proposes further revisions and meets environmental, environmental justice and climate change objectives. At least 20 states have challenged the Phase II rule in federal district court. The CEQ's changes could result in increased NEPA review timelines for projects involving agency action regarding federal lands, federal funds or federal permits or approvals. Additionally, in November 2024, a federal appeals court found that CEQ lacks statutory authority to issue NEPA regulations binding other federal agencies. However, the court's holding was confined to striking down the agencies’ action under review on separate grounds, and CEQ's Phase I and II rules remain in effect. However, in January 2025, President Trump issued executive orders (i) requiring CEQ to provide guidance on implementing NEPA and to propose rescinding and replacing CEQ's NEPA regulations with implementing regulations at the agency level; (ii) requiring the EPA to issue guidance on and to consider eliminating the social cost of carbon calculation from federal permitting or regulatory decisions; and (iii) instructing federal agencies to adhere to only the relevant legislated requirements for environmental reviews and to prioritize efficiency and certainty over any other objectives in such reviews. In February 2025, CEQ sent an interim final rule to the White House Office of Management and Budget that would immediately withdraw the NEPA implementing regulations. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our business and operations.

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 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 to 52% (compared to 2005 levels) by 2030. In addition, in September 2021, the Biden Administration publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030. At COP27, the United States 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 August 2024, the European Union adopted a regulation to track and reduce methane emissions in the energy sector, including requiring new monitoring, reporting and verification measures to be applied by exporters to the European Union by January 1, 2027 and "maximum methane intensity values" must be met by 2030 and every year thereafter. 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. 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. Most recently, at COP29, participants representing 159 countries met and, among other things, agreed on rules to operationalize international carbon markets under Article 6 of the Paris Agreement. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. However, in January 2025, President Trump issued an executive order directing immediate notice to the United Nations of the United States’ withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. The full impact of these actions remains uncertain at this time.

In recent years, the 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 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 and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a "waste emissions charge" on methane emissions from certain natural gas and oil facilities that are in excess of a specified threshold. In November 2024, the EPA finalized a rule implementing the IRA's waste emissions charge that took effect in January 2025. The waste 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 rule includes methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and 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 or 10 metric tons of methane per million barrels of oil sent to sale from facility if the facility sends no natural gas to sale. If a facility's methane emissions do not exceed the 0.2% threshold, no fee is assessed under the program. Further, in May 2024, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas systems (Subpart W). Among other things, the final rule (the Subpart W Revisions 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. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions and Waste Reduction Incentive Program in the IRA, and the Subpart W Revisions Rule may result in an increase in reported methane and other GHG emissions under Subpart W for many operators. The Subpart W Revisions Rule took effect in January 2025.

Furthermore, in May 2024, the EPA published final rules for carbon emission limits and guidelines for new, modified, reconstructed and existing fossil fuel-fired (i.e., coal, oil and gas-fired) power plants. The rules purport to reflect the best system of emissions reduction and use of technology-based improvements, including carbon capture and sequestration and low-GHG hydrogen. The rules also revise the NSPS for new fossil fuel-fired stationary combustion turbine units and existing fossil fuel-fired steam generating electric generating units (EGUs), create new GHG emissions guidelines for existing fossil fuel-fired steam generating EGUs and for existing large, frequently operated stationary combustion turbines. The rules require 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 coalition of 25 states, energy companies, utilities and fossil fuel industry groups immediately challenged the rules in federal court. In October 2024, the U.S. Supreme Court denied a request to stay the rule for new gas-fired and existing coal-fired power plants while the litigation continues. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. Additionally, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Consequently, future implementation and enforcement of these rules remains uncertain at this time.

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 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. 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 was appealed in December 2023 to the Supreme Court of Pennsylvania. In March 2024, Pennsylvania Governor Shapiro unveiled a proposal to adopt a carbon pricing program similar to RGGI and stated that he would pull Pennsylvania out of RGGI if the state legislature enacts his proposal. In September 2024, legislation that would repeal the state’s participation in RGGI passed the Pennsylvania Senate. 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, 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. Certain of California's climate disclosure rules took effect in January 2025, with the disclosure of Scope 1 and 2 GHG emissions data scheduled to take effect beginning in 2026.

Any legislation or regulatory programs at the international, federal, state or local 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. Further, the U.S. Supreme Court's decision in *Loper Bright Enterprises v. Raimondo* to overrule *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.* and end the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs. However, many of these initiatives at the international, state and local levels are expected to continue, and 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 transport and lower the value of our reserves.

Further, 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 our operations.

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.

In April 2024, the Bureau of Land Management (BLM) finalized a rule to reduce the waste of natural gas from venting, flaring and leaks during oil and gas production activities on federal and Native American leases. The final rule took effect in June 2024. However, in May 2024, the states of North Dakota, Texas, Montana, Wyoming and Utah challenged the rule. In September 2024, the U.S. District Court for the District of North Dakota granted a motion prohibiting the BLM from enforcing the rule against those states pending the outcome of the litigation. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Consequently, future implementation and enforcement of the final rule remains uncertain at this time.

Pipeline Safety and Maintenance Regulations. Our interstate natural gas pipeline system and natural gas storage assets are subject to regulation by the PHMSA. The PHMSA has established safety requirements pertaining to the design, installation, testing, construction, operation and maintenance of gas pipeline and storage facilities, including requirements that pipeline and storage operators develop a written qualification program for individuals performing covered tasks on pipeline facilities and implement pipeline and storage well integrity management programs. These integrity management plans require more frequent inspections and other preventive measures to ensure safe operation of oil and natural gas transportation pipelines and storage facilities in high population areas or facilities that are hard to evacuate and areas of daily concentrations of people.

Notwithstanding the investigatory and preventative maintenance costs incurred in our performance of customary pipeline and storage management activities, we may incur significant additional expenses if anomalous pipeline or storage conditions are discovered or more stringent safety requirements are implemented. For example, in April 2016, the PHMSA published a notice of proposed rulemaking addressing several integrity management topics and proposing new requirements to address safety issues for natural gas transmission and gathering lines, along with certain storage facilities (the Mega Rule). The PHMSA intended the Mega Rule to strengthen existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. Part I of the Mega Rule was promulgated in October 2019, with an effective date of July 1, 2020 (see discussion below). Part II was promulgated in November 2021, with an effective date of May 16, 2022 (see discussion below). Finally, Part III of the Mega Rule was promulgated in August 2022, with an effective date of May 24, 2023 (see discussion below).

Further, in June 2016, then-President Obama signed the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the 2016 Pipeline Safety Act), extending the PHMSA's statutory mandate under prior legislation through 2019. In addition, the 2016 Pipeline Safety Act empowered the PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing and also required the PHMSA to develop new safety standards for natural gas storage facilities by June 2018. Pursuant to those provisions of the 2016 Pipeline Safety Act, the PHMSA issued a final rule effective December 2, 2019 that expanded the agency's authority to impose emergency restrictions, prohibitions and safety measures and issued a final rule effective March 13, 2020 that strengthened the rules related to underground natural gas storage facilities, including well integrity, wellbore tubing and casing integrity.

The PHMSA has also published five final rules on pipeline safety applicable to us: "Enhanced Emergency Order Procedures;" "Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (also known as the Mega Rule Part I); and "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" (also known as the Mega Rule Part II); and "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" (also known as the Mega Rule Part III); and “Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards” (the valve rule). The Enhanced Emergency Order Procedures rule, which became effective on December 2, 2019, implements an existing statutory authorization for the PHMSA to issue emergency orders related to pipeline safety if an unsafe condition or practice, or a combination of unsafe conditions and practices, constitutes, or is causing an imminent hazard. Mega Rule Part I, which went into effect on July 1, 2020, requires operators of certain gas transmission pipelines that have been tested or that have inadequate records to determine the material strength of their lines by reconfirming the Maximum Allowable Operating Pressure (MAOP), and establishes a new Moderate Consequence Area for determining regulatory requirements for gas transmission pipeline segments outside of high consequence areas. The rule also establishes new requirements for conducting baseline assessments, incorporates into the regulations industry standards and guidelines regarding design, construction and in-line inspections (ILI), and new requirements for data integration and risk analysis in integrity management programs, including seismicity, manufacturing and construction defects, and crack and crack-like defects, and includes several requirements that allow operators to notify the PHMSA of proposed alternative approaches to achieving the objectives of the minimum safety standards.

Mega Rule Part II, which was finalized in November 2021 and went into effect on May 16, 2022, extends existing design, operational and maintenance, and reporting requirements to onshore natural gas gathering pipelines in rural areas. The rule requires operators of onshore gas gathering pipelines to report incidents and file annual reports (with the first annual reports submitted in Spring 2023) and creates new safety requirements that vary based on pipeline diameter and potential consequences of a failure. Mega Rule Part III, which was finalized in August 2022, went into effect on May 24, 2023. The rule requires operators of certain transmission pipelines to assess their integrity management practices and comply with enhanced corrosion control and mitigation timelines. It also establishes new requirements for pipeline inspections following an extreme weather event or natural disaster and provides enhanced guidance for pipeline repairs. The valve rule requires the installation of remote operated rupture mitigation valves on new or entirely replaced transmission and storage lines when valves are installed to meet valve spacing requirements. In addition, the valve rule includes requirements for operator actions to be taken when notified of a potential rupture that include notifying emergency response agencies and closing valves within a specified timeframe.

However, as discussed below, we do expect certain compliance costs to increase in the future, and we continue to assess the impact of compliance with these rules which could materially impact our future costs of operations and revenue from operations. For example, Mega Rule Part I requires MAOP reconfirmation of certain previously untested transmission pipeline segments, which are commonly referred to as ‘‘grandfathered’’ pipelines. Our grandfathered pipeline MAOP reconfirmation efforts, which we have initiated, may result in unanticipated testing and/or replacement costs. When reconfirming MAOP on certain of our grandfathered pipeline segments we may be required to remove portions of pipelines for testing, shut in certain pipelines, and/or may face significant operational or technical challenges when performing either a pressure test or an ILI examination, which could result in substantial costs related thereto, or to repairs, remediation, or replacing existing pipelines, and/or other mitigating actions that may be determined to be necessary as a result of the tests, as well as lost cash flows resulting from shutting down our pipelines during the pendency of any such actions, which could be material to our capital expenditures, earnings and competitive position. Additionally, ensuring complete compliance with the applicable Mega Rule compliance deadlines may cause us to incur significant additional expenses if anomalous pipeline conditions are discovered.

States are generally preempted by federal law in the area of pipeline safety, but state agencies may qualify to assume responsibility for enforcing federal regulations over intrastate pipelines. They may also promulgate additive pipeline safety regulations provided that the state standards are at least as stringent as the federal standards. Although many of our natural gas facilities fall within a class that is not subject to integrity management requirements, we may incur significant costs and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt transmission pipelines. The costs, if any, for repair, remediation, preventive or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of any such actions, could be material to our capital expenditures, earnings and competitive position.

Should we fail to comply with U.S. Department of Transportation regulations adopted under authority granted to the PHMSA, we could be subject to penalties and fines. The PHMSA has the statutory authority to impose civil penalties for pipeline safety violations up to a maximum of approximately $272,926 per day for each violation and approximately $2.7 million for a related series of violations. This maximum penalty authority established by statute will continue to be adjusted periodically to account for inflation. In addition, we could be required to make additional, unforeseen maintenance capital expenditures in the future for our regulatory compliance initiatives. Additionally, the adoption of new laws and regulations, such as the Mega Rule discussed above, could result in significant added costs or delays to in service or the termination of projects, which could have a material adverse effect on us in the future.

In December 2020, President Trump signed the "Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES Act) of 2020," which reauthorized the federal pipeline safety program that expired in 2019. The PIPES Act identifies areas where Congress believed additional oversight, research, or regulations was needed. The PIPES Act includes new mandates for the PHMSA to require operators to update, as needed, their emergency response plans and operating and maintenance plans. The PIPES Act also requires operators to manage records and update, as necessary, their existing district regulator stations to eliminate a common mode of failure. The PHMSA will also require that leak detection and repair programs consider the environment, the use of advance lead detection practices and technologies, and that operators be able to locate and categorize all leaks that are hazardous to human safety, the environment, or that can become hazardous. We have not incurred and do not anticipate incurring material capital expenditures in connection with complying with the PIPES Act.

Occupational Safety and Health Act. We are 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 March 2024, the FWS issued three final rules governing interagency cooperation, listing species and designating critical habitat, and expanding protection options for species listed as threatened pursuant to the ESA. 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 October 2021, the Department of the Interior 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 Department has not yet issued a proposed rule. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. Consequently, future implementation and enforcement 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 15 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Human Capital Resources

As of December 31, 2024, we had 1,461 full-time equivalent employees (i.e., excluding temporary employees and contractors), none of whom were subject to a collective bargaining agreement. Of our employee base, 77% are male and 23% are female. Approximately 56% of our permanent employees work remotely, with 95% residing in Pennsylvania, West Virginia, Texas or Ohio.

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.

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 Production, Midstream and Processing Operations

Drilling for, producing, gathering, transmitting, storing and processing natural gas are high-risk and costly activities with many uncertainties. Our future financial position, cash flows and results of operations depend on the success of our operating activities, which are subject to numerous risks beyond our control.

Many factors may curtail, delay, suspend or cancel our scheduled drilling projects, the development schedule of wells which we do not operate but in which we have a working interest (referred to as non-operated wells), and our gathering, transmission, storage and processing operations, 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, pipe, materials, qualified personnel, water (for hydraulic fracturing activities) or other natural resources needed for our operations;
- 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;
- aging infrastructure and mechanical or structural problems;
- failure of equipment, facilities or new technology;
- damage to pipelines, wells and storage assets, facilities, equipment, environmental controls and surrounding properties, and pipeline blockages or other operational interruptions, caused or exacerbated by natural phenomena, weather conditions, acts of sabotage, vandalism and terrorism;
- security risks, including cybersecurity incidents;
- inadvertent damage from construction, vehicles, and farm and utility equipment;
- lack of available capacity on interconnecting transportation pipelines;
- adverse weather conditions, such as flooding, droughts, freeze-offs, fires, 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;
- leaks, migrations or losses of natural gas as a result of issues regarding pipeline and/or storage equipment or facilities and, including with respect to storage assets, as a result of undefined boundaries, geologic anomalies, limitations in then-applied industry-standard testing methodologies, operational practices (including as a result of regulatory requirements), natural pressure migration and wellbore migration or other factors relevant to such storage assets;
- 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 or suspension of our operations, including 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 and other regulatory penalties.

The location of certain segments of our wells and pipeline systems in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the damages resulting from these risks. Accidents or other operating risks have resulted, and in the future could result, in loss of service available to our pipeline customers. Customer impacts arising from service interruptions on segments of our pipeline systems and/or our assets have included and/or may include, without limitation and as applicable, curtailments, limitations on our ability to satisfy customer contractual requirements, obligations to provide reservation charge credits to customers and solicitation of our existing customers by third parties for potential new projects that would compete directly with our existing services. Such circumstances could adversely impact our ability to retain customers and negatively impact our business, financial condition, results of operations, and cash flows.

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, pipe and qualified personnel or in obtaining water and other natural resources 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 flows and results of operation.

Significant portions of our assets have been in service for several decades. There could be unknown events or conditions, or increased maintenance or repair expenses and downtime, associated with our assets that could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Significant portions of our transmission and storage systems have been in service for several decades. The age and condition of these systems has contributed to, and could result in, adverse events, or increased maintenance or repair expenditures, and downtime associated with increased maintenance and repair activities, as applicable. Any such adverse events or any significant increase in maintenance and repair expenditures or downtime, or related loss of revenue, due to the age or condition of our systems could adversely affect our business, financial condition, results of operations, and cash flows.

Expanding our business by constructing new midstream assets subjects us to construction, business, economic, competitive, regulatory, judicial, environmental, political and legal uncertainties that are beyond our control.

The development and construction by us or our joint ventures of pipeline and storage facilities and the optimization of such assets involve numerous construction, business, economic, competitive, regulatory, judicial, environmental, political and legal uncertainties that are beyond our control, require the expenditure of significant amounts of capital and expose us to risks. Those risks include, but are not limited to:

- physical construction conditions, such as topographical, or unknown or unanticipated geological, conditions and impediments;
- construction site access logistics;
- crew availability and productivity and ability to adhere to construction workforce drawdown plans;
- adverse weather conditions;
- project opposition, including delays caused by landowners, advocacy groups or activists opposed to our projects and/or the natural gas industry through lawsuits or intervention in regulatory proceedings;
- evolving regulatory or legal requirements and related impacts therefrom, including additional costs of compliance;
- the application of time of year or other regulatory restrictions affecting construction;
- failure to meet customer contractual requirements;
- environmental conditions;
- vandalism and acts of sabotage;
- the lack of available skilled labor, equipment and materials (or escalating costs in respect thereof, including as a result of inflation and/or tariffs);
- issues regarding availability of or access to connecting infrastructure; 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)

Risks inherent in the construction of these types of projects, such as unanticipated geological conditions, challenging terrain in certain of our construction areas and severe or continuous adverse weather conditions, have adversely affected, and in the future could adversely affect, project timing, completion and costs, as well as increase the risk of loss of human life, personal injuries, significant damage to property or environmental contamination. Most notably, certain of these risks have been realized in the construction of the MVP, including construction-related risks and adverse weather conditions, and such risks or other risks may be realized in the future which may further adversely affect the timing and/or cost of the MVP and MVP Southgate (defined in Note 11 to the Consolidated Financial Statements).

Given such risks and uncertainties, our midstream projects or those of our joint ventures may not be completed on schedule, within budgeted cost or at all. As a further example, public participation, including by pipeline infrastructure opponents, in the review and permitting process of projects, through litigation or otherwise, has previously introduced, and in the future could introduce, uncertainty and adversely affect project timing, completion and cost. Further, civil protests regarding environmental justice, environmental health and safety, and social issues or challenges in project permitting processes related to such issues, including proposed construction and location of infrastructure associated with fossil fuels, poses an increased risk and may lead to increased litigation, legislative and regulatory initiatives and review at federal, state, tribal and local levels of government or permitting delays that can prevent or delay the construction of such infrastructure and realization of associated revenues.

Additionally, construction expenditures on projects generally occur over an extended period, yet we will not receive revenues from, or realize any material increases in cash flow as a result of, the relevant project until it is placed into service. Moreover, our cash flow from a project may be delayed or may not meet our expectations, including as a result of taxes which could potentially be calculated based on excess expenditures, inclusive of maintenance, incurred during extended court-driven construction delays. Furthermore, we may construct facilities to capture anticipated future growth in production and/or demand in a region in which such growth does not materialize or is delayed beyond our expectations. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return. Such issues in respect of the construction of midstream assets could adversely affect our business, financial condition, results of operations, and cash flows.

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, midstream 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, fires, 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 and our customers' 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 and midstream services 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 scheduled 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 6% 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, 2024, 2023 and 2022, we recorded impairment and expiration of leases of $97.4 million, $109.4 million and $176.6 million, respectively. Refer to Note 1 to the Consolidated Financial Statements.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations and future development.

We do not own all of the land on which our pipelines, storage systems and facilities have been constructed, and we have been, and in the future could be, subject to more onerous terms, and/or increased costs or delays, in attempting (or by virtue of the need to attempt) to acquire or to maintain use rights to land. Although many of these rights are perpetual in nature, we occasionally obtain the rights to construct and operate our pipelines and other facilities on land owned by third parties and governmental agencies for a specific period of time or in a manner in which certain facts could give rise to the presumption of the abandonment of the pipeline or other facilities. As has been the case in the past, if we were to be unsuccessful in negotiating or renegotiating rights-of-way or easements, we might have to institute condemnation proceedings on our FERC-regulated assets, the potential for which may have a negative effect on the timing and/or terms of FERC action on a project's certification application and/or the timing of any authorized activities, or relocate our facilities for non-regulated assets. The FERC has announced a policy that would presumptively stay the effectiveness of certain future construction certificates, which may limit when we are able to exercise condemnation authority. It is possible that Congress may amend Section 7 of the NGA to codify the FERC's presumptive stay or otherwise limit, modify, or remove the ability to utilize condemnation. It is also possible that a court may limit, modify or remove an operator's ability to utilize condemnation under Section 7 of the NGA. A loss of rights-of-way, lease or easements or a relocation of our non-regulated assets could have a material adverse effect on our business, financial condition, results of operations, and cash flow. Additionally, even when we own an interest in the land on which our pipelines, storage systems and facilities have been constructed, agreements with correlative rights owners have caused us to, and in the future may require that we, relocate pipelines and facilities or shut in storage systems and facilities to facilitate the development of the correlative rights owners' estate, or pay the correlative rights owners the lost value of their estate if they are not willing to accommodate development.

We may incur losses as a result of title defects in the properties we lease.

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 or developing planned midstream infrastructure, which may adversely impact our ability in the future to increase our production and reserves or meet customer demands for midstream services. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial position.

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 three-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, gathering, transmission 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 $3.40 per MMBtu to a low of $1.21 per MMBtu between the period from January 1, 2024 through December 31, 2024, and the daily spot prices for NYMEX West Texas Intermediate oil ranged from a high of $87.69 per barrel to a low of $66.73 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. Other producers could be similarly impacted by declines in natural gas prices, potentially resulting in decreased demand for our gathering and transmission services, thereby reducing our cash flows from such operations. 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 LOE, 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, and demand for our midstream services may decrease, diminishing the cash flows from such operations.

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.

Increased competition from other companies that provide gathering, transmission and storage of natural gas, or from alternative fuel or energy sources, could negatively impact demand for our midstream services, which could adversely affect our financial results.

Our ability to renew or replace existing contracts or add new contracts at rates sufficient to maintain or grow our Gathering segment and Transmission segment revenues and cash flows could be adversely affected by the activities of our midstream competitors. Our midstream systems compete primarily with other interstate and intrastate pipelines and storage facilities in the gathering, transmission and storage of natural gas. Some of our competitors have greater financial resources and may be better positioned to compete, including if the midstream industry moves towards greater consolidation. Some of these competitors may expand or construct gathering, transmission and storage systems that would create additional competition for the midstream services we provide to our customers. In addition, certain of our customers have developed or acquired their own gathering infrastructure, and may acquire or develop gathering, transmission or storage infrastructure in the future, which could have a negative impact on the demand for our midstream services depending on the location of such systems relative to our assets and our customers' drilling plans, commodity prices, existing contracts and other factors.

The policies of the FERC promoting competition in natural gas markets continue to have the effect of increasing the natural gas transmission and storage options for our customer base. As a result, in the future we could experience "turnback" of firm capacity as existing agreements expire. If we are unable to remarket this capacity or can remarket it only at substantially discounted rates compared to previous contracts, we may have to bear the costs associated with the turned back capacity. Increased competition could reduce the volumes of natural gas transported or stored on our systems or, in cases where we do not have long-term firm contracts, could force us to lower our transmission or storage rates.

Further, natural gas as a fuel competes with other forms of energy available to end-users, including coal, liquid fuels and, increasingly, renewable and alternative energy. Increases, whether driven by legislation, regulation or consumer preferences, in the availability and demand for renewable and alternative energy at the expense of natural gas (or increases in the demand for other sources of energy relative to natural gas based on price and other factors) could adversely affect the customers of our midstream services and lead to a reduction in demand for our natural gas gathering, transmission and storage services.

In addition, competition, including from renewable and alternative energy, could intensify the negative impact of factors that decrease demand for natural gas in the markets served by our systems, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers and/or additional volumes from existing customers as we seek to maintain and expand our midstream operations, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We may not be able to renew or replace expiring gathering, transmission or storage contracts at favorable rates, on a long-term basis or at all, and disagreements have occurred and may arise with contractual counterparties on the interpretation of existing or future contractual terms.

One of our exposures to market risk occurs at the time our existing gathering, transmission and storage contracts expire and are subject to renegotiation and renewal. As these contracts expire, we may have to negotiate extensions or renewals with existing customers or enter into new contracts with existing customers or other customers. We may be unable to do so on favorable commercial terms, if at all. Further, we also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. The extension or renewal of existing contracts and entry into new contracts depends on a number of factors beyond our control, including, but not limited to: (i) the level of existing and new competition to provide services to our markets; (ii) macroeconomic factors affecting natural gas economics for our current and potential customers; (iii) the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets; (iv) the extent to which the customers in our markets are willing to contract on a long-term basis or require capacity on our systems; (v) customers' existing and future downstream commitments; and (vi) the effects of federal, state or local regulations on the contracting practices of our customers and us. Additionally, disagreements may arise with contractual counterparties on the interpretation of contractual provisions, including during the negotiation, for example, of contract amendments required to be entered into upon the occurrence of specified events.

Any failure to extend or replace a significant portion of our existing gathering, transmission and storage contracts, or extending or replacing such contracts at unfavorable or lower rates or with lower or no associated firm reservation fee revenues, or other disadvantageous terms relative to the prior contract structure, or disagreements or disputes on the interpretation of existing or future contractual terms, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We may not be able to increase our customer throughput and resulting revenue due to competition and other factors, which could limit our ability to grow our Gathering segment and Transmission segment.

Our ability to increase our customer-subscribed pipeline capacity and throughput and resulting revenue is subject to numerous factors beyond our control, including competition from other producers' existing contractual obligations to competitors, the location of our assets relative to those of competitors for existing or potential midstream customers (or such customers' own midstream assets), takeaway capacity constraints out of the Appalachian Basin, commodity prices, producers' optionality in utilizing our (relative to third-party) systems to fill downstream commitments, and the extent to which we have available capacity when and where shippers require it. To the extent that we lack available capacity on our systems for volumes, or we cannot economically increase capacity, we may not be able to compete effectively with third-party systems for additional natural gas production in our areas of operation, and capacity constraints, as well as commodity prices, may, as has occurred in the past, adversely affect the degree to which natural gas production occurs in the Appalachian Basin, and relatedly the degree to which our midstream systems are utilized.

Our efforts to attract new midstream customers or larger commitments from existing customers may be adversely affected by our desire to provide services pursuant to long-term firm contracts and contracts with MVCs. Our potential midstream customers may prefer to obtain services under other forms of contractual arrangements which could require volumetric exposure or potentially direct commodity exposure, and we may not be willing to agree to such other forms of contractual arrangements.

A substantial majority of the services we provide on our transmission and storage systems are subject to long-term, fixed-price "negotiated rate" contracts that are subject to limited or no adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts, we could be unable to achieve the expected investment return under such contracts, and/or our business, financial condition, results of operations, and cash flows could be adversely affected.

It is possible that costs to perform services under our midstream contracts with "negotiated rates" could exceed the negotiated rates we have agreed to with our customers. If this occurs, it could decrease the cash flow realized by our midstream systems and, therefore, could have a material adverse effect on our business, financial condition, results of operations, and cash flows. Under FERC policy, a regulated service provider and a customer may mutually agree to a "negotiated rate," and that contract must be filed with and accepted by the FERC. As of December 31, 2024, approximately 99% of the contracted firm transmission capacity on our systems was subscribed under such "negotiated rate" contracts. Unless the parties to these "negotiated rate" contracts agree otherwise, the contracts generally may not be adjusted to account for increased costs that could be caused by inflation, GHG emission cost (such as carbon taxes, fees, or assessments) or other factors relating to the specific facilities being used to perform the services.

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), potential tariffs imposed by the United States or other countries on goods and natural resources, including natural gas and LNG, inflation and U.S. Federal Reserve interest rate adjustments in response thereto, and the availability and cost of credit, 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 and could impact the development schedule of our midstream customers, thereby resulting in decreased demand for, and revenue from, our midstream services. 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 and services 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, including enhanced disclosure obligations, (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, transport and sell. If we are not able to demonstrate that our products and services align with a transition to a low-carbon economy, the demand and prices for our products and services 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, iron, sand and water and therefore result in increased costs to our business.

Further, there have been efforts 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, which if successful, 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. 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, which could adversely affect our operating flexibility, business, financial condition, results of operations, and cash flows.

In 2024, we published, and in 2025 we updated, our Debt Retirement Plan. We intend to fund our Debt Retirement Plan through asset monetizations, such as the NEPA Non-Operated Asset Divestitures and the Midstream Joint Venture Transaction, and free cash flow; however, there can be no assurance that we will be able to generate sufficient monetization proceeds and free cash flow to execute our Debt Retirement Plan on our anticipated timeframe, if at all. Our ability to de-lever and the pace thereof will depend on our future financial and operating performance, which will be affected by the prevailing economic conditions and financial, business, regulatory and other factors, as well as the MVP Joint Venture's (defined in Note 11 to the Consolidated Financial Statements) ability to execute on project-level financing, some of which are beyond our control. If we are not able to successfully execute our Debt Retirement Plan or otherwise reduce our 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 substantial debt obligations could have significant adverse consequences on our business and future prospects, and restrictions in our debt agreements could limit our operating flexibility, growth and ability to engage in certain activities.

As of December 31, 2024, we had $9.3 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 our operations, future business opportunities, and our shareholder returns strategy;
- 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.

In addition, our level of indebtedness may be viewed negatively by credit rating agencies and our credit ratings may be lowered. Changes in our 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 facilities and our senior notes with adjustable rates, the rates available on new debt, our pool of investors and funding sources, and 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. As of February 14, 2025, EQT's senior notes were rated "Baa3" with a "Negative" 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). As of February 14, 2025, EQM Midstream Partners, LP's (our wholly-owned subsidiary, EQM) senior notes were rated "Ba2" with a "Stable" outlook by Moody's, "BBB–" with a "Stable" outlook by S&P and "BB+" with a "Stable" outlook by Fitch. Although we are not aware of any current plans of Moody's, S&P or Fitch to downgrade its rating of EQT’s or EQM’s senior notes, we cannot be assured that one or more of these rating agencies will not downgrade or withdraw entirely its rating of EQT’s or EQM's 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 senior notes with adjustable rates, the rates available on new 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.

Our debt agreements require us to comply with certain covenants. 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." If the price that we receive for our natural gas, NGLs and oil production deteriorates from current levels and continues for an extended period, or if demand for our midstream services decreases for a prolonged 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. If the payment of the debt is accelerated, our assets may be insufficient to repay such debt in full, and in turn our shareholders could experience a partial or total loss of their investment. EQT's revolving credit facility, Eureka's revolving credit facility, and certain of EQT's and EQM's senior notes each contain a cross default provision that applies to a default related to any other indebtedness the applicable borrower may have with an aggregate principal amount in excess of a specified threshold as set forth in the applicable debt documents

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 EQT's revolving credit facility and other external sources of capital. If we do not have sufficient borrowing availability under EQT's 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;
- our ability to obtain and/or maintain necessary rights-of-way, real-estate rights or permits or other government approvals, including approvals by regulatory agencies;
- our ability to successfully integrate the infrastructure we build or acquire with our existing systems;
- our success in securing or maintaining adequate customer commitments for our midstream services, including to use newly expanded facilities;
- the levels of our operating expenses; and
- our ability to access the public or private capital markets or borrow under EQT's revolving credit facility.

If our cash flows from operations or the borrowing capacity under EQT's 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 and infrastructure projects, which in turn could lead to a decline in our reserves, production, and demand for our midstream services, and could adversely affect our business, results of operations and financial position.

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 EQT's or EQM's credit ratings 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 EQT's revolving credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under EQT's existing line of credit if we experience 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, 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, building and acquiring new infrastructure, 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 operating 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.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport or process natural gas or do not accept deliveries of natural gas from us, our business, financial condition, cash flows, and results of operations could be adversely affected.

We depend on third-party pipelines and other facilities that provide receipt and delivery options to and from our transmission and storage systems. For example, our storage system and the MVP Joint Venture's transmission system interconnect, as applicable, with the following third-party interstate pipelines: Transcontinental Gas Pipe Line Company, LLC, East Tennessee Natural Gas, Texas Eastern, Eastern Gas Transmission, Columbia Gas Transmission, Tennessee Gas Pipeline Company, Rockies Express Pipeline LLC, National Fuel Gas Supply Corporation and ET Rover Pipeline, LLC, as well as multiple distribution companies. Similarly, our gathering systems have multiple delivery interconnects to multiple interstate pipelines. In the event that our or the MVP Joint Venture's access to such systems is impaired (or any third-party refuses to accept our or any of the MVP Joint Venture's deliveries), our or the MVP Joint Venture's operations could be adversely affected, resulting in adverse economic impact to us or the MVP Joint Venture.

Because we do not own these third-party pipelines or facilities, their continuing operation and access requirements are not within our control. If these or any other pipeline connections or facilities were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our or the MVP Joint Venture's ability to operate efficiently and ship natural gas to end markets could be restricted, as has occurred in the past. Any temporary or permanent interruption at any key pipeline interconnect or facility could have a material adverse effect on our business, financial condition, cash flows, and results of operations.

Substantially all of our producing properties and midstream infrastructure 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 and midstream infrastructure 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.

Due to the concentrated nature of our portfolio of natural gas properties and midstream assets, a number of our properties and demand for our midstream services 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 assets.

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.

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 GHG emissions, with third-party assurance of such data, and issue public reports summarizing 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. Compliance with these and any other federal, state or local disclosure requirements may cause us to incur additional (and potentially accelerate) compliance and reporting costs, certain of which could be material, including related to monitoring, collecting, analyzing and reporting new metrics and implementing systems and procuring additional necessary attestation. Such costs may adversely affect our future business, financial condition, results of operations, and liquidity.

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 and our midstream services.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, 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 United States 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 August 2024, the European Union adopted a regulation to track and reduce methane emissions in the energy sector. See Item 1., "Business-Regulation-Climate Change and Regulation of Methane and Other Greenhouse Gas Emissions" for more information. 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. Most recently, at COP29, participants representing 159 countries met and, among other things, agreed on rules to operationalize international carbon markets under Article 6 of the Paris Agreement. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States' withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. The full impact of these actions remains uncertain at this time.

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 the IRA, a $1 trillion legislative infrastructure package that 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 November 2024, the EPA finalized a rule implementing the IRA's waste emissions charge. The final rule includes methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and certain exemptions created by the IRA. Further, in May 2024, the EPA finalized revisions 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 took effect on January 1, 2025. The emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the IRA's waste emissions charge program. However, petitions for reconsideration to the EPA are pending and litigation in the D.C. Circuit has commenced. Additionally, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise or rescind all agency actions that are unduly burdensome on the identification, development or use of domestic energy resources. As a result, future implementation and enforcement of these rules remains uncertain at this time.

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 GHG 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 and our midstream services. 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 and our midstream services, 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.

The regulatory approval process for the construction of new transmission assets is very challenging, and, as demonstrated with the MVP, has resulted in significantly increased costs and delayed targeted in-service dates, and decisions by regulatory and/or judicial authorities in pending or potential proceedings relevant to the development of midstream assets, such as regarding the MVP Southgate project and/or expansions or extensions of the MVP, are likely to impact our or the MVP Joint Venture's ability to obtain or maintain in effect all approvals and authorizations, including as may be necessary to complete certain projects in a timely manner or at all, or our ability to achieve the expected investment returns on the projects.

Certain of our projects require regulatory approval from federal, state and/or local authorities prior to and/or in the course of construction, including any extensions from, expansions of or additions to our and the MVP Joint Venture's gathering, transmission and storage systems, as applicable. The approval process for certain projects has become increasingly slower and more difficult, due in part to federal, state and local concerns related to exploration and production, transmission and gathering activities and associated environmental impacts, and the increasingly negative public perception regarding, and opposition to, the oil and gas industry, including major pipeline projects like the MVP and MVP Southgate. Further, regulatory approvals and authorizations, even when obtained, have increasingly been subject to judicial challenge by activists requesting that issued approvals and authorizations be stayed and vacated.

Accordingly, authorizations needed for our or the MVP Joint Venture's projects, including any expansion of the MVP and the MVP Southgate project or other extensions, may not be granted or, if granted, such authorizations may include burdensome or expensive conditions or may later be stayed or revoked or vacated, as was repeatedly the case with the construction of the MVP. Significant delays in the regulatory approval process for projects, as well as stays and losses of critical authorizations and permits, should they be experienced, have the potential to significantly increase costs, delay targeted in-service dates and/or affect operations for projects (among other adverse effects), as has happened with the MVP and the originally certificated MVP Southgate project and could occur in the future in the case of authorizations required for our or the MVP Joint Venture's current or future projects, including in respect of developing expansions or extensions, such as expansion of the MVP and the MVP Southgate project.

Any such adverse developments and uncertainties could adversely affect our ability, and/or, as applicable, the ability for the MVP Joint Venture and its owners, including us, to achieve expected investment returns, adversely affect our willingness or ability and/or that of our joint venture partners to continue to pursue projects, and/or cause impairments, including to our equity investment in the MVP Joint Venture.

We have experienced and may further experience increased opposition with respect to our and the MVP Joint Venture's projects from activists in the form of lawsuits, intervention in regulatory proceedings and otherwise, which could result in adverse impacts to our business, financial condition, results of operations and cash flows. In particular, opponents were successful in past challenges with respect to the MVP. Opposition is ongoing regarding the MVP Southgate project and is expected for future projects, including any expansions of the MVP. If ongoing or future challenges are successful, it could result in significant, adverse impacts to our business, financial condition, results of operations and cash flows. Such opposition has made it increasingly difficult to complete projects and place them in service and, following any in service, may also affect operations or affect extensions and/or expansions of projects. Further, such opposition and/or adverse court rulings and regulatory determinations may have the effect of increasing the timeframe on necessary agency action to address actual or perceived concerns in prior adverse court rulings, or may have the effect of increasing the risk that at a future point joint venture partners may elect not to continue to pursue or fund a project, which could, absent additional project sponsors, significantly imperil the ability to complete the project. See also Item 1A., "Risk Factors – We have entered into joint ventures, and may in the future enter into additional or modify existing joint ventures, that might restrict our operational and corporate flexibility and divert our management's time and our resources. In addition, we exercise no control over joint venture partners and it may be difficult or impossible for us to cause these joint ventures or partners to take actions that we believe would be in our or the joint venture's best interests and these joint ventures are subject to many of the same risks to which we are subject." Challenges to our projects could adversely affect our business (including by increasing the possibility of investor activism), financial condition, results of operations, and cash flows.

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.

Our and the MVP Joint Venture's natural gas gathering, transmission and storage services, as applicable, are subject to extensive regulation by federal, state and local regulatory authorities. Changes in or additional regulatory measures adopted by such authorities, and related litigation, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our and the MVP Joint Venture's interstate natural gas transmission and storage operations, as applicable, are regulated by the FERC under the NGA and the NGPA and the regulations, rules and policies promulgated under those and other statutes. Our and the MVP Joint Venture's FERC-regulated operations are pursuant to tariffs approved by the FERC that establish rates (other than market-based rate authority), cost recovery mechanisms and terms and conditions of service to our customers. The FERC's authority extends to a variety of matters relevant to our operations.

Pursuant to the NGA, existing interstate transmission and storage rates, terms and conditions of service, and contracts may be challenged by complaint and are subject to prospective change by the FERC. Additionally, rate increases, changes to terms and conditions of service and contracts proposed by a regulated interstate pipeline may be protested and such actions can be delayed and may ultimately be rejected by the FERC. As of December 31, 2024, we and the MVP Joint Venture hold authority from the FERC to charge and collect (i) "recourse rates," which are the maximum rates an interstate pipeline may charge for its services under its tariff, (ii) "discount rates," which are rates below the "recourse rates" and above a minimum level, (iii) "negotiated rates," which involve rates that may be above or below the "recourse rates," provided that the affected customers are willing to agree to such rates and that the FERC has approved the negotiated rate agreement, and (iv) market-based rates for some of our storage services from which we derive a small portion of our revenues. As of December 31, 2024, approximately 99% of our contracted firm transmission capacity was subscribed to by customers under negotiated rate agreements under our tariff, rather than recourse, discount or market-based rate contracts. There can be no guarantee that we or the MVP Joint Venture will be allowed to continue to operate under such rates or rate structures for the remainder of those assets' operating lives. Customers, the FERC or other interested stakeholders, such as state regulatory agencies, may challenge our or the MVP Joint Venture's rates offered to customers or the terms and conditions of service included in our tariffs. Neither we nor the MVP Joint Venture have an agreement in place that would prohibit customers from challenging our or the MVP Joint Venture's rates or tariffs. Any successful challenge against rates charged for our or the MVP Joint Venture's transmission and storage services, as applicable, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Any changes to the FERC's policies regarding the natural gas industry may have an impact on us, including the FERC's approach to pro-competitive policies as it considers matters such as interstate pipeline rates and rules and policies that may affect rights of access to natural gas transmission capacity and transmission and storage facilities. The FERC and Congress may continue to evaluate changes in the NGA or new or modified FERC regulations or policies that may impact our or the MVP Joint Venture's operations and affect our or the MVP Joint Venture's ability to construct new facilities and the timing and cost of such new facilities, as well as the rates charged to our or the MVP Joint Venture's customers and the services provided.

Our and the MVP Joint Venture's significant construction projects generally require review by multiple governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any agency's delay in the issuance of, or refusal to issue, authorizations or permits, issuance of such authorizations or permits with unanticipated conditions, or the loss of a previously-issued authorization or permit, for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate (as was the case with MVP). Such delays, refusals, losses of permits, or resulting modifications to projects, certain of which was experienced with respect to the MVP project and the originally certificated MVP Southgate project, could materially and negatively impact the revenues and costs expected from these projects or cause us or our joint venture partners to abandon planned projects.

Failure to comply with applicable provisions of the NGA, the NGPA, federal pipeline safety laws and certain other laws, as well as with the regulations, rules, orders, restrictions and conditions associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties. For example, the FERC is authorized to impose civil penalties of up to approximately $1.6 million (adjusted periodically for inflation) per violation, per day for violations of the NGA, the NGPA or the rules, regulations, restrictions, conditions and orders promulgated under those statutes.

In addition, future federal, state or local legislation or regulations under which we or the MVP Joint Venture operate may have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We and our joint ventures may incur significant costs and liabilities as a result of performance of our pipeline and storage integrity management programs and compliance with increasingly stringent safety regulation.

The U.S. Department of Transportation, acting through PHMSA, and certain state agencies certificated by PHMSA, have adopted regulations requiring pipeline operators to develop an integrity management program for transmission pipelines located where a leak or rupture could impact high population sensitive areas (also known as High Consequence Areas) and newly defined Moderate Consequence Areas, and an integrity management program for storage wells, unless the operator effectively demonstrates by a prescriptive risk assessment that these operational assets have mitigated risks that could affect these predefined areas, as applicable. The regulations require operators, including us, to perform ongoing assessments of pipeline and storage integrity; identify and characterize applicable threats to pipeline segments and storage wells that could impact population sensitive areas; confirm maximum allowable operating pressures; maintain and improve processes for data collection, integration and analysis; repair and remediate facilities as necessary; and implement preventive and mitigating actions. In addition to population sensitive areas, PHMSA has adopted regulations extending existing design, operation and maintenance, and reporting requirements to onshore gathering pipelines in rural areas. Finally, new PHMSA regulations require operators of certain transmission pipelines to assess their integrity management and maintenance practices, comply with enhanced corrosion control and mitigation timelines, and follow new requirements for pipeline inspections following an extreme weather event or natural disaster.

The cost and financial impact of compliance will vary and depend on factors such as the number and extent of maintenance determined to be necessary as a result of the application of our integrity management programs, and such costs and financial impact could have a material adverse effect on us. Further, our pipeline and storage integrity management programs depend in part on inspection tools and methodologies developed, maintained, enhanced and applied, and certain testing conducted, by certain third parties, many of which are widely utilized within the natural gas industry. Advances in these tools and methodologies could identify potential and/or additional integrity issues for our assets. Consequently, we may incur additional costs and expenses to remediate those newly identified or potential issues, and we may not have the ability to timely comply with applicable laws and regulations. Additionally, pipeline and storage safety laws and regulations are subject to change and failures to comply with pipeline and storage safety laws and regulations, including changes in such laws and regulations or interpretations thereof that result in more stringent or costly safety standards, could have a material adverse effect on us. We may, and joint ventures of which we are the operator could, as has been the case with the MVP Joint Venture, become subject to consent orders and agreements relating to integrity matters. Failure to comply with any such consent order or agreements could have adverse effects on our business.

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, gather and transport 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 prior 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 proposed changes have included, (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 our operations, 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. Lastly, our tax returns are subject to audit by taxing authorities, and there is no assurance that tax authorities or courts will agree with the positions that we have reflected in our tax filings. Disagreements with tax authorities or courts could result in additional tax liabilities recorded by us or interest and penalties imposed on us, which could adversely impact our earnings, cash flow 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, production and midstream 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 and synergies expected from such transactions within our projected timeframe or at all, including with respect to the recently completed Equitrans Midstream Merger. Various factors, including prevailing market conditions, could negatively impact the benefits and synergies we expect to receive from these transactions. There can be no assurance that we will be able to successfully integrate companies and assets that we acquire, including Equitrans Midstream Corporation (Equitrans Midstream) and its subsidiaries, and the anticipated benefits of such strategic transactions may not be realized fully or at all or may take longer than expected. With respect to dispositions, 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.

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.

We have entered into joint ventures, and may in the future enter into additional or modify existing joint ventures, that might restrict our operational and corporate flexibility and divert our management's time and our resources. In addition, we exercise no control over joint venture partners and it may be difficult or impossible for us to cause these joint ventures or partners to take actions that we believe would be in our or the joint venture's best interests and these joint ventures are subject to many of the same risks to which we are subject.

We have entered into several joint ventures primarily pertaining to the construction and operation of certain midstream infrastructure, including the MVP Joint Venture, Eureka Midstream Holdings, LLC (Eureka Midstream Holdings) and the Midstream Joint Venture, and may in the future enter into additional joint venture arrangements with third parties. Joint venture arrangements may restrict our operational and corporate flexibility. Joint venture arrangements and dynamics can also divert management and operating resources in a manner that is disproportionate to our ownership percentage in such ventures. Because we do not control all of the decisions of our joint ventures or joint venture partners, it may be difficult or impossible for us to cause these joint ventures or partners to take actions that we believe would be in our or the joint venture's best interests. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing that we fund operating and/or capital expenditures, the timing and amount of which we may not control, and our joint venture partners may not act in a manner that we believe would be in our or the joint venture's best interests, may elect not to support further pursuit of projects, and/or may not satisfy their financial obligations to the joint venture. The loss of joint venture partner support in further pursuing or funding a project may significantly adversely affect the ability to complete the project. In addition, such joint ventures are subject to many of the same risks to which we are subject.

Acquisitions may disrupt our current plans or operations and may not be worth what we pay due to uncertainties in evaluating recoverable reserves, physical assets and other expected benefits, as well as potential liabilities.

Successful asset 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; 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 assets. We do not inspect every well, lease or pipeline that we acquire, and even when we inspect a well, lease or pipeline, 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 assets have substantially different operating and geological characteristics or are in different geographic locations than our existing assets.

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.

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.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

We maintain a management-level Enterprise Risk Committee, composed of our Chief Financial Officer, Chief Legal and Policy 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 2024. 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 (the 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 regarding cybersecurity matters and our enterprise cybersecurity program.

Our 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 preventing, identifying, assessing, mitigating, 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 technology providers 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 Chief Legal and Policy Officer 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, Ohio 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.

Environmental Proceedings

Pratt Storage Field Matter, Morgan Township, Pennsylvania. On October 31, 2018, a gas explosion occurred in Morgan Township, Greene County, Pennsylvania (the Pratt Incident), close in proximity to Equitrans, L.P.'s (one of our subsidiaries) Pratt Storage Field assets. Following the explosion, the Pennsylvania Department of Environmental Protection (PADEP), the Pennsylvania Public Utilities Commission and the PHMSA began investigating the Pratt Incident. The PADEP issued a final report and closed its investigation in August 2022, and we do not expect further inquiry from the PADEP on this matter; however, the Pennsylvania Public Utilities Commission and PHMSA investigations are still pending.

On October 23, 2023, Equitrans, L.P. received permission from the FERC to plug and abandon the AH Hupp 3660 storage well (Hupp Well) in the Pratt Storage Field that was the subject of the PADEP's investigation of the Pratt Incident. On October 22, 2024, Equitrans, L.P. received from the FERC an extension until January 31, 2025 to complete plugging and abandonment of the Hupp Well. On January 24, 2025, Equitrans, L.P. requested an additional extension of time, until July 31, 2025, to complete the plugging and abandonment of the Hupp Well.

On October 30, 2023, Equitrans, L.P. received a criminal complaint from the State Attorney General's Office charging Equitrans, L.P. with violations of Pennsylvania's Clean Streams Law (the Pratt Complaint), and generally alleging that: (i) natural gas leaked from the Hupp Well and into a water well and (ii) Equitrans, L.P. failed to conduct a stray gas investigation of the Pratt Incident. The Pratt Complaint carries the possibility of a monetary sanction, that if imposed could result in a fine in excess of $300,000; however, we expect that the resolution of this matter will not have a material adverse impact on our financial condition, results of operations or liquidity.

Rager Mountain Storage Field Venting, Jackson Township, Pennsylvania. On November 6, 2022, Equitrans Midstream became aware of natural gas venting from one of the storage wells, well 2244, at Equitrans, L.P.'s Rager Mountain natural gas storage facility (the Rager Mountain Facility), located in Jackson Township, a remote section of Cambria County, Pennsylvania. Venting at the Rager Mountain Facility was halted on November 19, 2022. Since the time of the incident, the PADEP has concluded its investigation and the PHMSA and other investigators are continuing to conduct civil and criminal investigations of the incident, and we are cooperating in such investigations.

On December 29, 2022, the PHMSA issued Equitrans Midstream a Notice of Proposed Safety Order that included proposed remedial requirements related to the Rager Mountain Facility incident, including, but not limited to, completing a root cause analysis, and subsequently, on May 26, 2023, the PHMSA issued a consent order to Equitrans Midstream requiring the completion of a root cause analysis and a remedial work plan and providing that Equitrans Midstream may not resume injection operations at the Rager Mountain Facility until authorized by the PHMSA. In August 2023, Equitrans Midstream submitted a root cause analysis to the PHMSA and later submitted a remedial work plan and injection plan seeking authority to resume injections at the Rager Mountain Facility using all wells in the facility except three, which remained disconnected from the storage field. On October 2, 2023, the PHMSA approved Equitrans Midstream's injection plan and Equitrans Midstream restarted injections at the Rager Mountain Facility on October 5, 2023, subject to certain pressure restrictions and other requirements in the PHMSA consent agreement. On November 16, 2023, the PHMSA issued a letter to Equitrans Midstream approving Equitrans Midstream's request to remove all pressure restrictions at the Rager Mountain Facility. On May 30, 2024, the PHMSA approved resuming operations for one of the three remaining wells excluded from the injection plan.

We plan to continue working with the PHMSA, pursuant to the consent order between PHSMA and Equitrans Midstream, regarding the remaining two disconnected wells at the Rager Mountain Facility. If additional penalties are pursued and ultimately imposed related to the Rager Mountain Facility incident, the penalties, individually and/or in the aggregate, may exceed $300,000; however, we expect that the resolution of this matter will not have a material adverse impact on our financial condition, results of operations or liquidity.

Plugging and Abandoning of Wells at the Holbrook Storage Reservoir, Center Township, Pennsylvania. One of our wholly owned subsidiaries, EQT Gathering, LLC, is the owner of fifteen inactive storage wells within the Holbrook storage reservoir located in Center Township, Pennsylvania. The wells have been inactive since 2021. On June 10, 2024, we were notified by the PADEP of alleged violations of the 2012 Oil and Gas Act, which requires wells located in Pennsylvania which are inactive for a period of twelve months to be reported to the PADEP as "inactive" and plugged. We are actively working with the PADEP to plug the inactive wells in accordance with the 2012 Oil and Gas Act and resolve this matter, and in connection therewith, we may be assessed a monetary penalty in excess of $300,000. We expect that the resolution of this matter will not have a material impact on our financial condition, results of operations or liquidity.

Item 4. Mine Safety Disclosures

Not Applicable.

Information about our Executive Officers (as of February 19, 2025)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
J.E.B. Bolen (46)	Executive Vice President Operations (2024)	Mr. Bolen was appointed as Executive Vice President Operations of EQT Corporation in October 2024. Before moving to that role, he served as EQT’s Senior Vice President Operations Planning from February 2023 to October 2024, and Vice President Operations Planning from July 2019 to February 2023. Prior to joining EQT, Mr. Bolen was Director, Upstream Development for the Shalennial Group LLC (digital oilfield solutions company), from March 2018 to July 2019.
Tony Duran (46)	Chief Information Officer (2019)	Mr. Duran was appointed as Chief Information Officer of EQT Corporation in July 2019. Prior to joining EQT, Mr. Duran ran PH6 Labs, a technology incubator he founded, from December 2017 to July 2019. Prior to that, he served as Chief Information Officer of Rice Energy Inc. (independent natural gas and oil company acquired by EQT in November 2017) from January 2016 to November 2017; and as Interim Chief Information Officer of Express Energy Services (oilfield services company for well construction and well testing services) from September 2015 to December 2015.
Lesley Evancho (47)	Chief Human Resources Officer (2019)	Ms. Evancho was appointed as Chief Human Resources Officer of EQT Corporation in July 2019. Prior to joining EQT, 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.
Sarah Fenton (46)	Executive Vice President Upstream (2024)	Ms. Fenton was appointed as Executive Vice President Upstream of EQT Corporation in October 2024. Previously, Ms. Fenton served as EQT’s Senior Vice President Asset Performance from February 2023 to October 2024, and Vice President Asset Performance from July 2019 to February 2023.
Todd M. James (42)	Chief Accounting Officer (2019)	Mr. James was appointed as Chief Accounting Officer of EQT Corporation in November 2019. Prior to joining EQT, Mr. James served as 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 Senior Director, Technical Accounting and Financial Reporting at Rice Energy Inc. from December 2014 through its acquisition by EQT 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 (44)	Chief Legal and Policy Officer and Corporate Secretary (2019)	Mr. Jordan was appointed as Chief Legal and Policy Officer of EQT Corporation in October 2024 and assumed the role of Corporate Secretary in November 2020. Prior to his current role, Mr. Jordan served as EQT’s Executive Vice President and General Counsel from July 2019 through September 2024. 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 to July 2019. Prior to that, he served as 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 in November 2017. From September 2005 to December 2013, Mr. Jordan was an Associate at Vinson & Elkins LLP (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 (36)	Chief Financial Officer (2023)	Mr. Knop was appointed as 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’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 to March 2022. Prior to joining EQT, 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 (43)	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'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 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 from October 2013 to November 2017. Prior to that, he served in a number of positions with Rice Energy, 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's Board of Directors since November 2017.

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Robert R. Wingo (46)	Executive Vice President Corporate Ventures & Midstream (2024)	Mr. Wingo was appointed as Executive Vice President Corporate Ventures & Midstream of EQT Corporation in October 2024. Prior to his current role, Mr. Wingo was EQT's Executive Vice President Corporate Ventures from September 2021 to October 2024. Prior to joining EQT, Mr. Wingo served as Managing Director at Encap Flatrock Midstream (venture capital and private equity investment fund) from March 2018 through August 2021. Prior to that he was Senior Vice President of Midstream and Marketing at Rice Energy Inc., as well as Chief Operating Officer and a member of the Board of Directors for Rice Midstream Partners LP, from June 2013 and December 2014, respectively, until their acquisition by EQT in 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 14, 2025, there were 3,084 shareholders of record of our common stock.

On February 6, 2025, our Board of Directors declared a quarterly cash dividend of $0.1575 per share of EQT common stock, payable on March 3, 2025, to shareholders of record at the close of business on February 18, 2025.

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

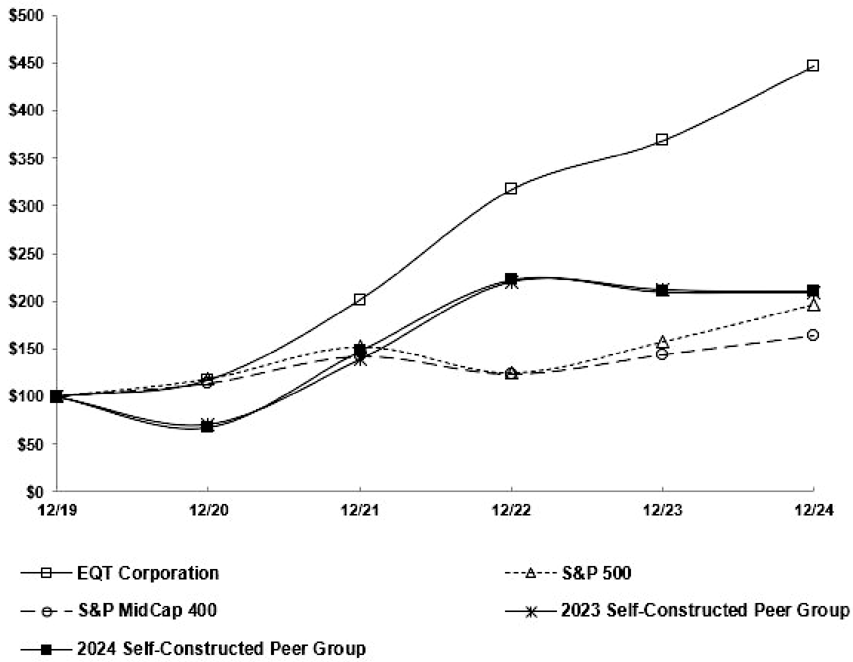
We did not repurchase any equity securities registered under Section 12 of the Exchange Act during the three months ended December 31, 2024.

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. 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. Further, on December 18, 2024, we announced that our Board of Directors approved an additional two-year extension of the Share Repurchase Program. As a result of the most recent extension, the Share Repurchase Program will expire on December 31, 2026, but it may be suspended, modified or discontinued at any time without prior notice. Repurchases under the Share Repurchase Program may be made from time to time in amounts 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. As of December 31, 2024, 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 following graph 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 2023 Self-Constructed Peer Group and the 2024 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 MidCap 400 index until October 2022, at which time our common stock was added to the S&P 500 Index. 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, 2019 and its relative performance is tracked through December 31, 2024. 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,
2023 Self-Constructed Peer Group and 2024 Self-Constructed Peer Group



*$100 invested on 12/31/2019 in stock, index or peer group, including reinvestment of dividends. Fiscal year ending December 31.

	12/19	12/20	12/21	12/22	12/23	12/24
EQT Corporation	$ 100.00	$ 117.25	$ 201.20	$ 317.08	$ 368.48	$ 447.25
S&P 500 Index	100.00	118.40	152.39	124.79	157.59	197.02
S&P MidCap 400 Index	100.00	113.66	141.80	123.28	143.54	163.54
2023 Self-Constructed Peer Group (a)	100.00	71.23	139.11	220.34	212.19	209.41
2024 Self-Constructed Peer Group (b)	100.00	67.93	147.63	222.46	209.88	210.77

(a) The 2023 Self-Constructed Peer Group includes the following twelve companies: Antero Resources Corp., APA Corp. (US), CNX Resources Corp., Comstock Resources Inc., Coterra Energy Inc., Devon Energy Corp., Diamondback Energy, Inc., Hess Corp., Matador Resources Co., Murphy Oil Corp., Ovintiv Inc. and Range Resources Corp. The 2023 Self-Constructed Peer Group is comprised of the companies included in our 2023 performance peer group (with the exception of (i) PDC Energy Inc., which was excluded for purposes of the stock performance graph because it was acquired by Chevron Corp. in August 2023, (ii) Pioneer Natural Resources Co., which was excluded for purposes of the stock performance graph because it was acquired by ExxonMobil in May 2024, (iii) Chesapeake Energy Corp. and Southwestern Energy Co., which were excluded for purposes of the stock performance graph because they completed a merger with each other in October 2024 and formed a new company which does not have five years of stock performance history, and (iv) Marathon Oil Corp., which was excluded for purposes of the stock performance graph because it was acquired by ConocoPhillips in November 2024), 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.

(b) The 2024 Self-Constructed Peer Group includes the following eleven companies: Antero Resources Corp., APA Corp. (US), CNX Resources Corp., Comstock Resources Inc., Coterra Energy Inc., Devon Energy Corp., Diamondback Energy Inc., Matador Resources Co., Murphy Oil Corp., Ovintiv Inc. and Range Resources Corp. The 2024 Self-Constructed Peer Group is comprised of the companies included in our 2024 performance peer group (with the exception of (i) Chesapeake Energy Corp, which was excluded for purposes of the stock performance graph because it merged with Southwestern Energy Co. in October 2024, and (ii) Marathon Oil Corp., which was excluded for purposes of the stock performance graph because it was acquired by ConocoPhillips in November 2024), 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 2024 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."

Recent and Significant Events

Midstream Joint Venture Transaction

On December 30, 2024, in connection with the completion of the Midstream Joint Venture Transaction, the Midstream Joint Venture received $3.5 billion of cash consideration, net of certain transaction fees and expenses, from a third-party investor in exchange for a noncontrolling equity interest in the Midstream Joint Venture. We used the proceeds from the Midstream Joint Venture Transaction to repay outstanding borrowings under the Bridge Credit Facility (defined in Note 10 to the Consolidated Financial Statements) and the Term Loan Facility and a portion of outstanding borrowings under EQT's revolving credit facility. Borrowings under the Bridge Credit Facility were used to fund the redemption and repurchase of certain of EQM's senior notes, including pursuant to the EQM Tender Offer (defined in Note 10 to the Consolidated Financial Statements).

NEPA Non-Operated Asset Divestitures and NEPA Gathering System Acquisition

Results of operations for 2024 include the results of our operation of assets received as consideration for the First NEPA Non-Operated Asset Divestiture, which closed on May 31, 2024. Such assets received included the remaining 16.25% equity interest in the NEPA Gathering System (defined in Note 6 to the Consolidated Financial Statements) (which was the sole remaining minority interest following our acquisition of a 33.75% equity interest in the NEPA Gathering System Acquisition (defined in Note 6 to the Consolidated Financial Statements) on April 11, 2024), resulting in our 100% ownership of the NEPA Gathering System. See Note 7 to the Consolidated Financial Statements.

In addition, on December 31, 2024, we completed the Second NEPA Non-Operated Asset Divestiture. See Note 7 to the Consolidated Financial Statements. We used the proceeds from the Second NEPA Non-Operated Asset Divestiture of $1.25 billion, subject to customary post-closing purchase price adjustments and transaction costs, to repay a portion of outstanding borrowings under EQT's revolving credit facility.

Equitrans Midstream Merger

Results of operations for 2024 include the results of our operation of assets acquired in the Equitrans Midstream Merger, which closed on July 22, 2024. Following the completion of the Equitrans Midstream Merger, we own a gathering system with 1,975 miles of gathering lines (including gathering lines owned prior to the Equitrans Midstream Merger) and a transmission and storage system with approximately 950 miles of FERC-regulated, interstate pipelines. See Note 6 to the Consolidated Financial Statements.

For the period from July 22, 2024 through December 31, 2024, our consolidated gathering expense decreased due to our ownership of the gathering and transmission assets acquired in the Equitrans Midstream Merger. Our ownership of such assets will continue to positively impact our Production segment's gathering expense, with a corresponding increase to our Production segment's affiliate transportation and processing expense, which is eliminated in consolidation. This relationship will be prominent for full year 2025 results and beyond.

Tug Hill and XcL Midstream Acquisition

Results of operations for 2024 and the second half of 2023 include the results of our operation of assets acquired in the Tug Hill and XcL Midstream Acquisition (defined in Note 6 to the Consolidated Financial Statements), which closed on August 22, 2023.

Trends and Uncertainties

On March 4, 2024, we announced our decision to strategically curtail approximately 1.0 Bcfe per day of gross production (the Strategic Curtailment) beginning on February 24, 2024 in response to the low natural gas price environment resulting from warm winter weather and elevated storage inventories. The Strategic Curtailment resulted in total decreased sales volume of 107 Bcfe for 2024. In addition, certain operators of wells in which we have a non-operating working interest also curtailed production in 2024. For 2024, we estimate that our total expected sales volume was negatively impacted by approximately 130 to 140 Bcfe of curtailments, including our Strategic Curtailment of 107 Bcfe and curtailments by certain operators of wells in which we have a non-operating working interest.

Low natural gas prices or volatility in the natural gas market may result in adjustments to our 2025 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 2025 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.

In connection with the recent U.S. election and corresponding inauguration of President Trump on January 20, 2025, the President executed several executive orders, some of which impact the oil and gas industry, and he and others in Congress have indicated the potential for further changes to regulations, many of which could impact the oil and gas industry, as well as the institution of tariffs on foreign goods and services. It is uncertain at this time to what extent such changes in regulations and tariffs will impact our business. A changing regulatory environment could increase our costs to comply with such regulations or make us susceptible to lawsuits or fines for failure to comply with such regulations. Further, tariffs on foreign goods and services could result in other countries instituting tariffs on U.S. goods and services, which could impact the price of natural gas, increase the price of supplies and raw materials that we rely on to conduct our business, and could impact interest rates. A changing regulatory environment and domestic or foreign tariffs could ultimately impact our future sales volume, operating revenues and expenses, per unit metrics and capital expenditures.

Lastly, we expect commodity prices to be volatile through 2025 due to macroeconomic uncertainty, changes to the regulatory environment and geopolitical tensions, including developments pertaining to Russia's invasion of Ukraine, conflicts in the Middle East and potential further imposition of domestic and foreign tariffs. 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.

Consolidated Results of Operations

Net income attributable to EQT Corporation for 2024 was $231 million, $0.45 per diluted share, compared to $1,735 million, $4.22 per diluted share, for 2023. The decrease was attributable primarily to a lower gain on derivatives, increased depreciation, depletion and amortization, increased other operating expenses and increased net interest expense, partly offset by the gains on the NEPA Non-Operated Asset Divestitures, decreased income tax expense, increased pipeline revenues and decreased transportation and processing expense.

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, 2023, which is incorporated herein by reference, for discussion and analysis of consolidated results of operations for the year ended December 31, 2022.

We did not recast our discussion and analysis of financial condition and results of operations for the year ended December 31, 2022 for our change in reportable segments as such change does not materially change our historic comparative discussion of our financial condition and results of operations for the years ended December 31, 2023 and 2022 included within the 2023 Annual Report. Prior to the Equitrans Midstream Merger, we operated our business as a single segment and did not generate material third-party gathering operating income. Further, in our judgment, we do not believe such a recast is necessary to an understanding of our business, financial condition, changes in financial condition and results of operations. See Note 2 to the Consolidated Financial Statements for financial information by business segment, including our profit and loss metric and capital expenditures for the year ended December 31, 2022 and segment assets as of December 31, 2022.

See "Average Realized Price Reconciliation" for a discussion and calculation of our average realized price, which is based on our Production segment's adjusted operating revenues (Production adjusted operating revenues), a non-GAAP supplemental financial measure that has been reconciled from total Production operating revenues in "Non-GAAP Financial Measures Reconciliation." See "Business Segment Results of Operations" for a discussion of segment operating revenues and expenses 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, including by business segment.

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 ($/Mcfe), which is based on Production adjusted operating revenues, a non-GAAP supplemental financial measure. Production adjusted operating revenues is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Production adjusted operating revenues should not be considered as an alternative to total Production operating revenues. See "Non-GAAP Financial Measures Reconciliation" for a reconciliation of Production adjusted operating revenues from total Production operating revenues, the most directly comparable financial measure calculated in accordance with United States generally accepted accounting principles (GAAP).

	Years Ended December 31,	
	2024	2023
	(Thousands, unless otherwise noted)	
NATURAL GAS		
Sales volume (MMcf)	2,086,441	1,907,343
NYMEX price ($/MMBtu)	$ 2.30	$ 2.74
Btu uplift	0.13	0.14
Natural gas price ($/Mcf)	$ 2.43	$ 2.88
Basis ($/Mcf) (a)	$ (0.41)	$ (0.51)
Cash settled basis swaps ($/Mcf)	(0.07)	(0.03)
Average differential, including cash settled basis swaps ($/Mcf)	$ (0.48)	$ (0.54)
Average adjusted price ($/Mcf)	$ 1.95	$ 2.34
Cash settled derivatives ($/Mcf)	0.64	0.34
Average natural gas price, including cash settled derivatives ($/Mcf)	$ 2.59	$ 2.68
Natural gas sales, including cash settled derivatives	$ 5,401,642	$ 5,112,278
LIQUIDS		
NGLs, excluding ethane:		
Sales volume (MMcfe) (b)	87,564	64,859
Sales volume (Mbbl)	14,594	10,810
NGLs price ($/Bbl)	$ 39.13	$ 36.39
Cash settled derivatives ($/Bbl)	(0.30)	(1.27)
Average NGLs price, including cash settled derivatives ($/Bbl)	$ 38.83	$ 35.12
NGLs sales, including cash settled derivatives	$ 566,808	$ 379,663
Ethane:		
Sales volume (MMcfe) (b)	44,586	34,441
Sales volume (Mbbl)	7,431	5,740
Ethane price ($/Bbl)	$ 6.03	$ 6.00
Ethane sales	$ 44,806	$ 34,417
Oil:		
Sales volume (MMcfe) (b)	9,568	9,630
Sales volume (Mbbl)	1,595	1,605
Oil price ($/Bbl)	$ 58.67	$ 59.93
Oil sales	$ 93,551	$ 96,191
Total liquids sales volume (MMcfe) (b)	141,718	108,930
Total liquids sales volume (Mbbl)	23,620	18,155
Total liquids sales	$ 705,165	$ 510,271
TOTAL		
Total natural gas and liquids sales, including cash settled derivatives (c)	$ 6,106,807	$ 5,622,549
Total sales volume (MMcfe)	2,228,159	2,016,273
Average realized price ($/Mcfe)	$ 2.74	$ 2.79

(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) Also referred to in this report as Production adjusted operating revenues, a non-GAAP supplemental financial measure.

Non-GAAP Financial Measures Reconciliation

The table below reconciles Production adjusted operating revenues, a non-GAAP supplemental financial measure, from total Production operating revenues, the most comparable financial measure calculated in accordance with GAAP. See Note 2 to the Consolidated Financial Statements for a reconciliation of total Production operating revenues to EQT Corporation operating revenues as reported in the Statements of Consolidated Operations.

Production 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. Production adjusted operating revenues is defined as total Production operating revenues, less the revenue impact of changes in the fair value of derivative instruments prior to settlement and Production net marketing services and other revenues. We believe that Production adjusted operating revenues provides useful information to investors regarding our financial condition and results of operations because it helps facilitate comparisons of operating performance and earnings trends across periods. Production adjusted operating revenues reflects only the impact of settled derivative contracts; thus, the measure excludes the often-volatile revenue impact of changes in the fair value of derivative instruments prior to settlement. The measure also excludes Production net marketing services and other revenues, which consists of costs of, and recoveries on, pipeline capacity releases and other revenues.

	Years Ended December 31,	
	2024	2023
	(Thousands, unless otherwise noted)	
Total Production operating revenues	$ 5,009,833	$ 6,896,358
(Deduct) add:		
Production gain on derivatives	(67,880)	(1,838,941)
Net cash settlements received on derivatives (a)	1,217,895	900,650
Premiums paid for derivatives that settled during the period	(45,454)	(322,869)
Production net marketing services and other	(7,587)	(12,649)
Production adjusted operating revenues, a non-GAAP financial measure	$ 6,106,807	$ 5,622,549
Total sales volume (MMcfe)	2,228,159	2,016,273
Average sales price ($/Mcfe)	$ 2.21	$ 2.50
Average realized price ($/Mcfe)	$ 2.74	$ 2.79

(a) For the years ended December 31, 2024 and 2023, composed of net cash settlements received on NYMEX natural gas hedge positions of approximately $1,374 million and $976 million , respectively, and net cash settlements paid on basis and liquids hedge positions of $157 million and $76 million, respectively. Net cash settlements received on derivatives are included in average realized price but may not be included in operating revenues.

Business Segment Results of Operations

Operating segments are revenue-producing components of an entity for which separate financial information is produced internally and reviewed by the chief operating decision maker to measure financial performance and allocate resources.

Prior to the completion of the Equitrans Midstream Merger, we reported our results of operations as a single consolidated segment. Thereafter, and as a result thereof, we adjusted our internal reporting structure and our chief operating decision maker changed the manner in which he measures financial performance and allocates resources to incorporate the gathering and transmission assets we acquired in the Equitrans Midstream Merger. Hence, our operations expanded to comprise three discrete segments reflective of our three lines of business of Production, Gathering and Transmission. Accordingly, the manner in which we report our operations has been changed retrospectively, with certain prior period amounts recast between our Production segment and Gathering segment.

The following sections summarize operating income and certain operational measures by our three reportable segments. We believe this information is useful to investors for evaluating our financial condition, results of operations and trends and uncertainties of our segments. See Note 2 to the Consolidated Financial Statements for financial information by business segment.

Certain amounts, including cash and cash equivalents, debt, income taxes and other amounts related to our headquarters function as well as amounts related to our energy transition initiatives are managed on a consolidated basis and, as such, have not been allocated to our reportable segments. Changes to these amounts are discussed under "Other Income Statement Items."

PRODUCTION

	Years Ended December 31,			
	2024	**2023**	**Change**	**% Change**
	(Thousands, unless otherwise noted)			
Total sales volume (MMcfe)	2,228,159	2,016,273	211,886	10.5
Average daily sales volume (MMcfe/d)	6,088	5,524	564	10.2
Average sales price ($/Mcfe)	$ 2.21	$ 2.50	$ (0.29)	(11.6)
Operating revenues:				
Sales of natural gas, NGLs and oil	$ 4,934,366	$ 5,044,768	$ (110,402)	(2.2)
Gain on derivatives	67,880	1,838,941	(1,771,061)	(96.3)
Pipeline, net marketing services and other	7,587	12,649	(5,062)	(40.0)
Total operating revenues	5,009,833	6,896,358	(1,886,525)	(27.4)
Operating expenses:				
Transportation and processing:				
Gathering	775,114	1,282,402	(507,288)	(39.6)
Transmission	846,563	642,688	203,875	31.7
Processing	293,939	232,170	61,769	26.6
Transportation and processing to affiliate (a)	704,094	148,830	555,264	373.1
Total transportation and processing	2,619,710	2,306,090	313,620	13.6
LOE	196,771	143,274	53,497	37.3
Production taxes	180,236	95,727	84,509	88.3
Exploration	2,735	3,330	(595)	(17.9)
Selling, general and administrative (b)	244,450	236,171	8,279	3.5
Production depletion	2,013,120	1,702,198	310,922	18.3
Other depreciation and depletion	3,550	3,113	437	14.0
(Gain) loss on sale/exchange of long-lived assets	(764,431)	17,445	(781,876)	(4,481.9)
Impairment and expiration of leases	97,368	109,421	(12,053)	(11.0)
Other operating expenses	12,696	9,177	3,519	38.3
Total operating expenses	4,606,205	4,625,946	(19,741)	(0.4)
Operating income	$ 403,628	$ 2,270,412	$ (1,866,784)	(82.2)
Per Unit ($/Mcfe):				
Gathering	$ 0.35	$ 0.64	$ (0.29)	(45.3)
Transmission	0.38	0.32	0.06	18.8
Processing	0.13	0.12	0.01	8.3
Transportation and processing to affiliate (a)	0.32	0.07	0.25	357.1
LOE	0.09	0.07	0.02	28.6
Production taxes	0.08	0.05	0.03	60.0
Selling, general and administrative (b)	0.11	0.12	(0.01)	(8.3)
Production depletion	0.90	0.84	0.06	7.1

(a) Transportation and processing to affiliate represents intercompany transactions with our Gathering and Transmission segments, which are eliminated in consolidation.
(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast as the necessary information is not available and the cost to develop such information would be excessive.

Sales of natural gas, NGLs and oil. Sales of natural gas, NGLs and oil decreased for 2024 compared to 2023 by approximately $110 million, of which approximately $640 million was attributable to lower average sales price, which was partly offset by approximately $530 million attributable to increased sales volumes. The average sales price decreased for 2024 compared to 2023 due to a lower NYMEX price, partly offset by lower basis spreads and higher NGLs price. Sales volume increased for 2024 compared to 2023 primarily as a result of sales volume increases of 164 Bcfe from the assets acquired in the Tug Hill and XcL Midstream Acquisition as well as increases from wells turned-in-line, partly offset by sales volume decreases of 107 Bcfe from the Strategic Curtailment and net decreases of 21 Bcfe due to the First NEPA Non-Operated Asset Divestiture. The increase in sales volume had a favorable impact on per unit costs for 2024 compared to 2023.

Production gain on derivatives. For 2024, we recognized a gain on derivatives of approximately $68 million related primarily to increases in the fair market value of our NYMEX swaps and options of approximately $377 million due to decreases in NYMEX forward prices, partly offset by decreases in the fair market value of our basis swaps of approximately $309 million. For 2023, we recognized a gain on derivatives of approximately $1,839 million related primarily to increases in the fair market value of our NYMEX swaps and options of approximately $1,830 million due to decreases in NYMEX forward prices as well as increases in the fair market value of our basis swaps of approximately $9 million.

Transportation and processing

<u>Gathering.</u> Gathering expense decreased on an absolute and per Mcfe basis for 2024 compared to 2023 due primarily to our Gathering segment's ownership of the gathering assets acquired in the Equitrans Midstream Merger, our Transmission segment's ownership of the transmission and storage assets acquired in the Equitrans Midstream Merger and our Gathering segment's ownership of the additional interest in the NEPA Gathering System acquired in the NEPA Gathering System Acquisition and as consideration for the First NEPA Non-Operated Asset Divestiture.

<u>Transmission.</u> Transmission expense increased on an absolute and per Mcfe basis for 2024 compared to 2023 due primarily to capacity charges related to the in service of the MVP (which commenced long-term firm capacity obligations on July 1, 2024) of approximately $165 million, additional contracted capacity on the Columbia Gas and Transco pipelines of an aggregate approximate $47 million and credits received in 2023 from pipeline credits of approximately $14 million. We record our equity earnings from our investment in the MVP Joint Venture in income from investments in our Statements of Consolidated Operations.

<u>Processing.</u> Processing expense increased on an absolute and per Mcfe basis for 2024 compared to 2023 due primarily to increased processing expense from the liquids-rich properties acquired in the Tug Hill and XcL Midstream Acquisition of approximately $40 million and increased volumes of gas requiring processing from wells that we turned-in-line in 2024.

<u>Transportation and processing to affiliate.</u> Affiliate transportation and processing expense increased on an absolute and per Mcfe basis for 2024 compared to 2023 due primarily to our Gathering segment's ownership of the gathering assets acquired in the Equitrans Midstream Merger, our Transmission segment's ownership of the transmission and storage assets acquired in the Equitrans Midstream Merger and our Gathering segment's ownership of the additional interest in the NEPA Gathering System acquired in the NEPA Gathering System Acquisition and as consideration for the First NEPA Non-Operated Asset Divestiture. In addition, affiliate transportation and processing expense increased on a per Mcfe basis for 2024 compared to 2023 due to our Gathering segment's ownership of the gathering assets acquired in the Tug Hill and XcL Midstream Acquisition during the third quarter of 2023.

LOE. LOE increased on an absolute and per Mcfe basis for 2024 compared to 2023 due primarily to increased LOE from the operation and maintenance of our assets, including assets acquired in the Tug Hill and XcL Midstream Acquisition and the Equitrans Midstream Merger and water assets internally-developed in the prior year, as well as increased salt water disposal costs.

Production taxes. Production tax expense increased on an absolute and per Mcfe basis for 2024 compared to 2023 due to increased property tax expense of approximately $63 million primarily from the assets acquired in the Tug Hill and XcL Midstream Acquisition and higher price as well as increased severance tax expense of approximately $24 million from increased sales volume in West Virginia.

Selling, general and administrative. Selling, general and administrative expense increased on an absolute basis for 2024 compared to 2023 due primarily to higher legal and professional services costs as well as higher personnel costs due to increased workforce headcount. In addition, we did not recast selling, general and administrative expense for periods prior to the Equitrans Midstream Merger closing date and, upon the Equitrans Midstream Merger closing date, we adjusted our basis for selling, general and administrative expense allocation for multi-segment reporting.

Depreciation and depletion. Production depletion expense increased on an absolute and per Mcfe basis for 2024 compared to 2023 due to increased sales volume and higher annual depletion rate.

(Gain) loss on sale/exchange of long-lived assets. During 2024, we recognized a gain on the First NEPA Non-Operated Asset Divestiture of approximately $299 million and a gain on the Second NEPA Non-Operated Asset Divestiture of approximately $463 million. See Note 7 to the Consolidated Financial Statements. During 2023, we recognized a loss on sale/exchange of long-lived assets of approximately $17 million related to acreage trade agreements where the carrying value of the acres traded exceeded the fair value of the acres received.

Impairment and expiration of leases. During 2024 and 2023, we recognized impairment and expiration of leases related to leases that we no longer expect to extend or develop prior to their expiration based on our development plan.

Other operating expenses. We recognized approximately $13 million and $9 million of other operating expenses for 2024 and 2023, respectively. Other operating expenses increased for 2024 compared to 2023 due primarily to increased rig release expense and increased legal and environmental reserves, including from settlements, partly offset by proceeds received in 2024 from business interruption insurance claim recoveries. See Note 1 to the Consolidated Financial Statements for a summary of consolidated other operating expenses.

GATHERING

	Years Ended December 31,			
	2024	2023	Change	% Change
	(Thousands, unless otherwise noted)			
Gathered volume (BBtu/d):				
Firm capacity	5,277	—	5,277	100
Volumetric-based services	4,234	976	3,258	334
Total gathered volume	9,511	976	8,535	874
Operating revenues:				
Loss on derivatives	$ (16,763)	$ —	$ (16,763)	100
Firm reservation fee revenue	313,987	—	313,987	100
Volumetric-based fee revenue (a)	452,476	161,395	291,081	180
Total operating revenues	749,700	161,395	588,305	365
Operating expenses:				
Operating and maintenance	89,897	15,699	74,198	473
Selling, general and administrative (b)	38,837	—	38,837	100
Depreciation	89,513	17,066	72,447	425
Gain on sale/exchange of long-lived assets	(22)	—	(22)	100
Total operating expenses	218,225	32,765	185,460	566
Operating income	$ 531,475	$ 128,630	$ 402,845	313

(a) For agreements structured with MVCs, includes volumes up to the contractual MVC; volumes in excess of the contractual MVC are reported under volumetric-based services.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast as the necessary information is not available and the cost to develop such information would be excessive.

Gathering revenues and expenses increased for 2024 compared to 2023 primarily from the gathering assets acquired in the Equitrans Midstream Merger during the third quarter of 2024 and in the Tug Hill and XcL Midstream Acquisition during the third quarter of 2023. Prior to the completion of the Equitrans Midstream Merger, we did not own gathering assets that provided firm gathering services.

TRANSMISSION

Prior to the completion of the Equitrans Midstream Merger, we did not have transmission or storage assets.

		Year Ended December 31, 2024
		(Thousands, unless otherwise noted)
Transmission pipeline throughput (BBtu/d):		
Firm capacity (a)		3,695
Interruptible capacity		24
Total transmission pipeline throughput		3,719
Average contracted firm transmission reservation commitments (BBtu/d)		4,779
Operating revenues:		
Firm reservation fee revenue	$	183,088
Volumetric-based fee revenue		34,968
Other revenues		237
Total operating revenues		218,293
Operating expenses:		
Operating and maintenance		20,496
Selling, general and administrative		17,183
Depreciation		33,505
Amortization of intangible assets		5,901
Loss on sale/exchange of long-lived assets		409
Total operating expenses		77,494
Operating income	$	140,799

(a) Includes all volumes associated with firm capacity contracts, including volumes in excess of firm capacity.

Other Income Statement Items

Other operating expenses. We recognized $337.2 million and $74.9 million of corporate other operating expenses for 2024 and 2023, respectively. Corporate other operating expenses increased for 2024 compared to 2023 due primarily to transaction costs related to the Equitrans Midstream Merger of $304.8 million and higher legal reserves, partly offset by lower transaction costs related to the Tug Hill and XcL Midstream Acquisition. See Note 1 to the Consolidated Financial Statements for a summary of consolidated other operating expenses.

Total transaction costs related to the Equitrans Midstream Merger recognized during 2024 included severance and other termination benefits and stock-based compensation costs of $165.4 million, of which $60.8 million was cash and $104.6 million was non-cash.

Income from investments. Income from investments increased for 2024 compared to 2023 due primarily to equity earnings from our investment in the MVP Joint Venture of $78.8 million, partly offset by a decrease in the fair value of our investment in the Investment Fund (defined in Note 11 to the Consolidated Financial Statements).

Other income. Other income increased for 2024 compared to 2023 due to proceeds received from insurance claim recoveries of $19.1 million related to the assets acquired in the Tug Hill and XcL Midstream Acquisition and dividends received from our investment in the Investment Fund.

Loss on debt extinguishment. During 2024, we recognized a loss on debt extinguishment of $68.3 million due primarily to premiums and financing costs paid on our redemption and repurchase of certain of EQM's senior notes, including pursuant to the EQM Tender Offer, and non-cash losses related to our write off of the unamortized fair value adjustments of those redeemed and repurchased EQM senior notes and unamortized deferred issuance costs of the Term Loan Facility. See Note 10 to the Consolidated Financial Statements.

Interest expense, net. Net interest expense increased for 2024 compared to 2023 due primarily to interest expense on EQM's senior notes, increased interest expense on our borrowings under EQT's revolving credit facility, interest expense on EQT's 5.750% senior notes issued in January 2024, lower interest income earned on cash on hand and interest expense on Eureka Midstream, LLC's (Eureka) borrowings under its revolving credit facility, partly offset by decreased interest expense from our repayment and repurchase of certain of EQT's senior notes as well as higher capitalized interest from the assets acquired in the Tug Hill and XcL Midstream Acquisition. See Note 10 to the Consolidated Financial Statements.

Income tax expense. See Note 9 to the Consolidated Financial Statements.

Net income (loss) attributable to noncontrolling interests. During 2024, we recognized $11.4 million of net income attributable to noncontrolling interests of Eureka Midstream Holdings, a consolidated joint venture in which we acquired an equity interest as a result of the Equitrans Midstream Merger. Sees Note 1 and 6 to the Consolidated Financial Statements.

Capital Resources and Liquidity

Although we cannot provide any assurance, we believe cash flows from operating activities and availability under EQT's revolving credit facility should be sufficient to meet our cash requirements, including, 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.

Purchase Obligations

We have commitments to pay demand charges under long-term contracts and binding precedent agreements with various pipelines as well as charges for processing capacity to extract heavier liquid hydrocarbons from the natural gas stream. In addition, we have commitments to pay for services related to our operations, including electric hydraulic fracturing services and purchase equipment, materials and sand. See Note 15 to the Consolidated Financial Statements for a summary of aggregated future payments for these commitments.

Unrecognized Tax Benefits

As of December 31, 2024, we had a total reserve for unrecognized tax benefits of $9.0 million and an additional reserve of $60.4 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 2019 in September 2024. We are currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities. See Note 9 to the Consolidated Financial Statements for further discussion.

Planned Capital Expenditures and Sales Volume

In 2025, we expect to spend approximately $2.3 billion to $2.5 billion on total capital expenditures. We expect to fund our capital expenditures with cash generated from operations and, if required, borrowings under EQT's 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 2025 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 addition, our gathering and transmission businesses are capital intensive, requiring significant investment to develop new facilities and maintain and upgrade existing operations. In 2025, we expect our sales volume to be 2,175 Bcfe to 2,275 Bcfe.

Material Cash Requirements

We have contractual commitments under our debt agreements, including interest payments and principal repayments. See Note 10 to the Consolidated Financial Statements for a summary of such contractual commitments, including maturity dates.

Operating Activities

Net cash provided by operating activities was $2,827 million and $3,179 million for 2024 and 2023, respectively. The decrease was due primarily to changes in working capital from movements in the market price for natural gas and timing of payments as well as higher cash operating expenses (including from transaction costs related to the Equitrans Midstream Merger), higher net interest expense and higher share-based compensation expense. Such decreases were partly offset by higher net cash settlements received on derivatives, lower net premiums paid on derivatives, higher cash operating revenues (including from pipeline revenues on assets acquired in the Equitrans Midstream Merger) and higher distributions from equity method investments (including approximately $53 million from our investment in the MVP Joint Venture).

Our cash flows from operating activities, including changes in working capital, 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 $1,580 million and $4,314 million for 2024 and 2023, respectively. The decrease was attributable primarily to the proceeds received from the NEPA Non-Operated Asset Divestitures in 2024 and lower cash paid for acquisitions in 2024 (primarily for the NEPA Gathering System Acquisition) compared to 2023 (primarily for the Tug Hill and XcL Midstream Acquisition), partly offset by increased capital expenditures and capital contributions made to our investment in the MVP Joint Venture of approximately $145 million.

The following table summarizes our capital expenditures by business segment.

	Years Ended December 31,	
	2024	**2023**
	(Millions)	
Production:		
Reserve development (a)	$ 1,653	$ 1,587
Land and lease	156	130
Other production infrastructure	71	63
Capitalized interest, capitalized overhead and other	124	98
Total Production	2,004	1,878
Gathering	202	32
Transmission	31	—
Other corporate items	29	15
Total capital expenditures	2,266	1,925
(Deduct) add: Non-cash items (b)	(12)	94
Total cash capital expenditures	$ 2,254	$ 2,019

(a) Capital expenditures for reserve development included capital expenditures for water infrastructure of $79.8 million and $35.9 million for 2024 and 2023, respectively.

(b) Represents the net impact of non-cash capital expenditures, including the effect of timing of receivables from working interest partners, accrued capital expenditures, transfers to or from inventory as assets are completed or assigned to a project 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 $1,126 million and $243 million for 2024 and 2023, respectively. For 2024, the primary uses of financing cash flows were our repayment and retirement of debt, repayment of EQM's revolving credit facility, payment of dividends and cash paid for taxes to net settle share-based incentive awards. For 2024, the primary sources of financing cash flows were net proceeds from the sale of units of the Midstream Joint Venture, proceeds from the issuance of EQT's 5.750% senior notes, net borrowings under EQT's revolving credit facility and proceeds from the net settlement of the Capped Call Transactions (defined in Note 10 to the Consolidated Financial Statements). For 2023, the primary uses of financing cash flows were our repayment and retirement of debt, payment of dividends and repurchase and retirement of EQT common stock, and the primary source of financing cash flows was proceeds from the Term Loan Facility borrowings.

See Note 10 to the Consolidated Financial Statements for further discussion of our debt.

On February 6, 2025, our Board of Directors declared a quarterly cash dividend of $0.1575 per share of EQT common stock, payable on March 3, 2025, to shareholders of record at the close of business on February 18, 2025.

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 10 to the Consolidated Financial Statements for discussion of redemptions and repurchases of debt and Note 12 to the Consolidated Financial Statements for discussion of repurchases of EQT common stock.

Security Ratings and Financing Triggers

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 independently 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 4 to the Consolidated Financial Statements for a description of what is deemed investment grade.

The table below reflects the credit ratings and rating outlooks assigned to EQT's debt instruments as of February 14, 2025.

Rating agency	Senior notes	Outlook
Moody's Investors Service, Inc. (Moody's)	Baa3	Negative
S&P Global Ratings (S&P)	BBB–	Stable
Fitch Ratings Service (Fitch)	BBB–	Stable

The table below reflects the credit ratings and rating outlooks assigned to EQM's debt instruments as of February 14, 2025.

Rating agency	Senior notes	Outlook
Moody's	Ba2	Stable
S&P	BBB–	Stable
Fitch	BB+	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 facilities, the interest rate on our senior notes with adjustable rates, the rates available on new 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 EQT's revolving credit facility and Eureka's revolving credit 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. EQT's revolving credit facility contains financial covenants that require us to have a total debt to total capitalization ratio no greater than 65%. As of December 31, 2024, we were in compliance with all EQT, Eureka and EQM debt provisions and covenants under our debt agreements.

See Note 10 to the Consolidated Financial Statements for a discussion of borrowings under EQT's revolving credit facility and Eureka's revolving credit 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 14, 2025. 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 2025(a)	Q2 2025	Q3 2025	Q4 2025
Hedged Volume (MMDth)	332	336	281	281
Hedged Volume (MMDth/d)	3.7	3.7	3.1	3.1
Swaps – Short				
Volume (MMDth)	250	290	281	95
Avg. Price ($/Dth)	$ 3.49	$ 3.11	$ 3.26	$ 3.27
Calls – Short				
Volume (MMDth)	188	46	—	137
Avg. Strike ($/Dth)	$ 4.19	$ 3.48	$ —	$ 5.49
Puts – Long				
Volume (MMDth)	82	46	—	186
Avg. Strike ($/Dth)	$ 3.19	$ 2.83	$ —	$ 3.30
Option Premiums				
Cash Settlement of Deferred Premiums (millions)	$ —	$ —	$ —	$ (45)

(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 4 to the Consolidated Financial Statements for further discussion of our hedging program.

Off-Balance Sheet Arrangements

As of December 31, 2024, we did not have any material off-balance sheet arrangements other than the commitments described in Note 15 to the Consolidated Financial Statements.

Commitments and Contingencies

See Note 15 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, relate to our more significant judgments and estimates used in the preparation of our Consolidated Financial Statements. Actual results could differ from our estimates.

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, 2024, we estimate that a 1% change in proved reserves would decrease or increase 2025 depletion expense by approximately $10 million and $21 million, respectively, based on current production estimates for 2025.

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 9 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 is a "critical accounting estimate" 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. When evaluating whether or not a valuation allowance should be established, we exercise judgment on whether it is more likely than not (a likelihood of more than 50%) that a portion or all of our deferred tax assets will not be realized. To determine whether a valuation allowance is needed, we consider all available evidence, both positive and negative, including carrybacks, tax planning strategies, reversals of deferred tax assets and liabilities and forecasted future taxable income. To determine the amount of financial statement benefit recorded for uncertain tax positions, we consider 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. To the extent that a valuation allowance or uncertain tax position is established or increased or decreased during a period, we record an income tax expense or benefit 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. Changes in our assumptions are sensitive to numerous factors; however, based on income before taxes for the years ended December 31, 2024, 2023 and 2022, we estimate that a 1% change in our effective tax rate would decrease or increase income tax expense by approximately $3 million, $21 million and $23 million, respectively.

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 5 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 is a "critical accounting estimate" 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.

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 15 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 is a "critical accounting estimate" 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.

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 2024, we completed the Equitrans Midstream Merger. 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 in the Equitrans Midstream Merger.

We believe business combinations is a "critical accounting estimate" 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.

Property, Plant and Equipment (Including Gas, NGLs and Oil Producing Properties). We use the successful efforts method of accounting for gas, NGLs and oil producing activities. See Note 1 to the Consolidated Financial Statements for a discussion of the fair value measurement and any impairment of our oil and gas properties and other property, plant and equipment as well as our evaluation of the recoverability of capitalized costs of unproved oil and gas properties.

We believe the accounting for our property, plant and equipment, including our gas, NGLs and oil producing properties, is a "critical accounting estimate" because the evaluations of impairment of proved properties involve significant judgment about future events, including future sales prices of natural gas and NGLs, future production costs, the amount of natural gas and NGLs recorded and timing of recoveries, as well as discount and inflation rates. In addition, evaluations of impairment of our other property, plant and equipment also involve significant judgement about future events, including assumptions about future cash flows, discount rates and operating levels. Significant changes in these estimates could result in the costs of our property, plant and equipment, including our proved and unproved properties, not being recoverable, which would require us 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 impairment of our proved and unproved oil and gas properties, impairment of other property, plant and equipment. 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."

Intangible Assets. Refer to Notes 1 and 6 to the Consolidated Financial Statements for a discussion of our intangible assets. We evaluate our intangible assets for impairment when indicators of impairment are present.

We believe impairment of intangible assets is a "critical accounting estimate" because the determination of whether an indicator of impairment has occurred and if further evaluation of impairment is required involves significant judgment about future events, including shifts in the market price of the assets, changes in the extent or manner in which the assets are being used, changes in legal factors of the business climate that could affect the value of the assets or a more-likely-than-not expectation that the assets will be sold or otherwise disposed of before the end of their previously estimated useful lives.

Investments in Unconsolidated Entities. Refer to Notes 1 and 11 to the Consolidated Financial Statements for a discussion of our investments in unconsolidated entities. We evaluate our investments in unconsolidated entities 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.

We believe the impairment of investments in unconsolidated entities is a "critical accounting estimate" because evaluations of impairment involve significant judgment about future events, such as our ability to recover the carrying value of our investment or the investee's inability to generate cash flows sufficient to justify the carrying value of our investment.

Goodwill. Goodwill is evaluated for impairment annually as of October 1 or more frequently if indicators of impairment exist. A significant amount of judgement is involved in determining if an indicator of impairment has occurred. Such indicators may include, among others, deterioration in general economic conditions, negative developments in equity and credit markets, adverse changes in the market environments in which we operate, increases in operating costs or other factors that could have a negative effect on earnings and cash flows or a trend of negative or declining cash flows over multiple periods.

We test goodwill for impairment on a qualitative or quantitative basis. When performing a qualitative impairment test, we consider a number of factors in our assessment, such as: general economic conditions, performance equity and credit markets, industry and market conditions, market capitalization, earnings and cash flow trends. When performing a quantitative impairment test, we may use a combination of the income and market approach to estimate the fair value of our reporting units.

Refer to Note 1 to the Consolidated Financial Statements for further discussion of our goodwill impairment assessment process.

We believe the impairment of goodwill is a "critical accounting estimate" because a significant amount of judgement is involved in determining whether an indicator of impairment has occurred. In addition, the estimation of the fair value of a reporting unit involves significant judgment and is sensitive to changes in assumptions, including changes in our stock price, weighted-average cost of capital, forecasted cash flows, terminal growth rates and industry multiples. Changes to assumptions could materially affect the estimated fair value of our reporting units and the resulting conclusion on impairment could materially affect our results of operations and financial position. In addition, future assumptions and estimates may materially differ from current assumptions and 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 and, similarly, could adversely affect timing of development of additional reserves and production that is accessible by our pipeline and storage assets and limit growth in, or may reduce the demand for, and usage of, our gathering or transmission and storage services. Price declines and sustained periods of low natural gas and NGLs prices could also have an adverse effect on the creditworthiness of our gathering, transmission and storage customers and related ability to pay firm reservation fees under long-term contracts. 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 4 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, 2024 and 2023 would increase the fair value of our natural gas derivative commodity instruments by approximately $283 million and $204 million, respectively. A hypothetical increase of 10% in the NYMEX natural gas price on December 31, 2024 and 2023 would decrease the fair value of our natural gas derivative commodity instruments by approximately $340 million and $482 million, respectively. For purposes of this analysis, we applied the 10% change in the NYMEX natural gas price on December 31, 2024 and 2023 to our natural gas derivative commodity instruments as of December 31, 2024 and 2023 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 5 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 EQT's revolving credit facility, Eureka's revolving credit facility and (prior to its payoff and termination) the Term Loan Facility. In addition, changes in Eureka's Consolidated Leverage Ratio (defined in that certain Credit Agreement, dated May 13, 2021, among Eureka, Sumitomo Mitsui Banking Corporation, as administrative agent, the lenders party thereto from time to time and any other persons party thereto from time to time, as amended, governing Eureka's revolving credit facility (the Eureka Credit Agreement)) as a result on Eureka's liquidity needs, operating results or distributions to its members affect the interest rate Eureka pays on borrowings under its revolving credit facility. None of the interest we pay on EQT's or EQM's senior notes fluctuates based on changes to market interest rates. A 1% increase in interest rates for the borrowings under EQT's revolving credit facility, Eureka's revolving credit facility and the Term Loan Facility during 2024 would have increased interest expense by approximately $15.6 million.

Interest rates for EQT's revolving credit facility and EQT's 7.000% senior notes fluctuate based on changes to the credit ratings assigned to EQT's senior notes by Moody's, S&P and Fitch. Interest rates for EQT's other outstanding senior notes and EQM's senior notes do not fluctuate based on changes to the credit ratings assigned to EQT's or EQM's respective 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 10 to the Consolidated Financial Statements for further discussion of our debt and Note 5 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 20%, or $93 million, of our OTC derivative contracts outstanding at December 31, 2024 had a positive fair value. Approximately 86%, or $912 million, of our OTC derivative contracts outstanding at December 31, 2023 had a positive fair value.

As of December 31, 2024, we were not in default under any derivative contracts and had no knowledge of default by any counterparty to our derivative contracts. During 2024, 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.

As of December 31, 2024, no one lender of the large group of financial institutions in the syndicate for EQT's revolving credit facility held more than 10% of the financial commitments thereunder. In addition, as of December 31, 2024, no one lender of the large group of financial institutions in the syndicate for Eureka's revolving credit facility held more than 13% of the financial commitments thereunder. 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

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, 2024 and 2023, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, 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 19, 2025 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, 2024, the net book value of the Company's proved oil and natural gas properties was \$19,497 million, and depreciation and depletion (DD&A) expense of the Company's Production segment was \$2,017 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 based on geological and engineering evaluations of in-place hydrocarbon volumes. Significant judgment is required by the Company’s engineers in evaluating geological and engineering 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, 2024. 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 those engineers 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 internal and external engineers 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 internal and external engineers 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 to the Company's reserve report.

Valuation of Acquired property, plant and equipment and the investment in the MVP Joint Venture related to the Equitrans Midstream Merger

Description of the Matter	As described in Note 6 to the consolidated financial statements, on July 22, 2024, the Company completed the Equitrans Midstream Merger. The Company's accounting for the Equitrans Midstream Merger included determining the fair value of the acquired property, plant and equipment (PP&E) and the investment in the MVP Joint Venture. The determination of fair value of the PP&E and investment in the MVP Joint Venture included significant judgment and assumptions by management, including future revenue, future operating costs, and a market-based discount rate. Auditing the Company's valuation of PP&E and the investment in the MVP Joint Venture involved a high degree of subjectivity as the determination of fair value was based on assumptions as described above which include future market and economic conditions.
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 external valuation advisors 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 PP&E and investment in the MVP Joint Venture included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. The audit procedures 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 assessed the reasonableness of management's assumptions by comparing the key market-related assumptions, such as the market-based discount rate used to develop the fair value estimates.

Accounting for the new Midstream Joint Venture

Description of the Matter	As more fully described in Note 8 to the consolidated financial statements, on November 22, 2024, the Company entered into a contribution agreement (the Contribution Agreement) with an affiliate of Blackstone Credit & Insurance (the BXCI Affiliate) to form a new midstream joint venture (the Midstream Joint Venture). On December 30, 2024, the transactions contemplated by the Contribution Agreement were consummated and, among other things, (i) EQM and certain of its subsidiaries contributed certain midstream assets (through the contribution of certain entities and equity interests) to the Midstream Joint Venture in exchange for 364,285,715 Class A Units in the Midstream Joint Venture and (ii) the BXCI Affiliate contributed $3.5 billion of cash (net of certain transaction fees and expenses) to the Midstream Joint Venture in exchange for 350,000,000 Class B Units in the Midstream Joint Venture (the Class B units). The Company determined the Class B units should be classified as noncontrolling interests within permanent equity. We identified management's evaluation of whether the Class B units should be classified as noncontrolling interests within permanent equity as a critical audit matter. Management applied judgment in assessing relevant terms, provisions, and other conditions, relative to the applicable accounting guidance, to determine the appropriate classification of the Class B units noncontrolling interests. Auditing these assessments made by management involved challenging auditor judgment due to the extent of specialized skills or knowledge required.
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 accounting for the Midstream Joint Venture. For example, we tested controls over the initial recognition and measurement of the Midstream Joint Venture, including the recording of the noncontrolling interest. To test the initial accounting for the Midstream Joint Venture, our audit procedures included, among others, inspection of the underlying agreements and testing management's application of the relevant accounting guidance, including the determination of the balance sheet classification of the noncontrolling interest. We involved professionals with specialized skill and knowledge to assist in evaluating the appropriateness of the accounting for the Midstream Joint Venture, including conclusions reached with respect to the recognition of the noncontrolling interest.

/s/ Ernst & Young LLP

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

Pittsburgh, Pennsylvania

February 19, 2025

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, 2024, 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, 2024, based on the COSO criteria.

As indicated in the accompanying Managements' Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Equitrans Midstream which are included in the 2024 consolidated financial statements of the Company and constituted approximately 25% of total assets as of December 31, 2024 and approximately 5% of total operating revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Equitrans Midstream.

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, 2024 and 2023, the related consolidated statements of operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2024 and the related notes and the financial statement schedule listed in the Index at Item 15(a), and our report dated February 19, 2025 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 19, 2025

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

	2024	2023	2022
	(Thousands, except per share amounts)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	$ 4,934,366	$ 5,044,768	$ 12,114,168
Gain (loss) on derivatives	51,117	1,838,941	(4,642,932)
Pipeline, net marketing services and other	287,826	25,214	26,453
Total operating revenues	5,273,309	6,908,923	7,497,689
Operating expenses:			
Transportation and processing	1,915,616	2,157,260	2,116,976
Production	377,007	239,001	298,388
Operating and maintenance	110,393	15,699	2,597
Exploration	2,735	3,330	3,438
Selling, general and administrative	336,724	236,171	252,645
Depreciation, depletion and amortization	2,162,350	1,732,142	1,665,962
(Gain) loss on sale/exchange of long-lived assets	(764,044)	17,445	(8,446)
Impairment and expiration of leases	97,368	109,421	176,606
Impairment of contract asset	—	—	214,195
Other operating expenses	349,864	84,043	57,331
Total operating expenses	4,588,013	4,594,512	4,779,692
Operating income	685,296	2,314,411	2,717,997
(Income) loss from investments	(76,039)	(7,596)	4,931
Other income	(25,983)	(1,231)	(11,280)
Loss on debt extinguishment	68,299	80	140,029
Interest expense, net	454,825	219,660	249,655
Income before income taxes	264,194	2,103,498	2,334,662
Income tax expense	22,079	368,954	553,720
Net income	242,115	1,734,544	1,780,942
Less: Net income (loss) attributable to noncontrolling interests	11,538	(688)	9,977
Net income attributable to EQT Corporation	$ 230,577	$ 1,735,232	$ 1,770,965
Income per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	509,597	380,902	370,048
Net income attributable to EQT Corporation	$ 0.45	$ 4.56	$ 4.79
Diluted (Note 12):			
Weighted average common stock outstanding	514,593	413,224	406,495
Net income attributable to EQT Corporation	$ 0.45	$ 4.22	$ 4.38

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

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

	2024	2023	2022
		(Thousands)	
Net income	$ 242,115	$ 1,734,544	$ 1,780,942
Other comprehensive income, net of tax:			
Other postretirement benefits liability adjustment, net of tax: $252, $59 and $488	363	310	1,617
Comprehensive income	242,478	1,734,854	1,782,559
Less: Comprehensive income (loss) attributable to noncontrolling interests	11,538	(688)	9,977
Comprehensive income attributable to EQT Corporation	$ 230,940	$ 1,735,542	$ 1,772,582

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

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2024	2023
	(Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 202,093	$ 80,977
Accounts receivable (less allowance for credit losses: $12,529 and $663)	1,132,608	823,695
Derivative instruments, at fair value	143,581	978,634
Income tax receivable	97,378	91,414
Prepaid expenses and other	139,019	38,255
Total current assets	1,714,679	2,012,975
Property, plant and equipment	44,505,504	33,817,169
Less: Accumulated depreciation and depletion	12,757,686	10,866,999
Net property, plant and equipment	31,747,818	22,950,170
Investments in unconsolidated entities	3,617,397	92,666
Net intangible assets	215,257	22,595
Goodwill	2,079,481	—
Other assets	455,623	206,692
Total assets	$ 39,830,255	$ 25,285,098
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt	$ 320,800	$ 292,432
Accounts payable	1,177,656	1,272,522
Derivative instruments, at fair value	446,519	186,363
Accrued interest	167,157	80,520
Other current liabilities	349,417	205,003
Total current liabilities	2,461,549	2,036,840
Revolving credit facility borrowings	150,000	—
Term Loan Facility borrowings	—	1,244,265
Senior notes	8,853,377	4,176,180
Note payable to EQM Midstream Partners, LP	—	82,236
Deferred income taxes	2,851,103	1,904,821
Other liabilities and credits	1,236,090	1,059,939
Total liabilities	15,552,119	10,504,281
Equity:		
Common stock, no par value, shares authorized: 1,280,000 and 640,000, shares issued: 596,870 and 419,896	18,014,711	12,093,986
Retained earnings	2,585,238	2,681,898
Accumulated other comprehensive loss	(2,321)	(2,684)
Total common shareholders' equity	20,597,628	14,773,200
Noncontrolling interest in consolidated subsidiaries	3,680,508	7,617
Total equity	24,278,136	14,780,817
Total liabilities and equity	$ 39,830,255	$ 25,285,098

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,

	2024	2023	2022
		(Thousands)	
Cash flows from operating activities:			
Net income	$ 242,115	$ 1,734,544	$ 1,780,942
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	14,732	384,666	534,612
Depreciation, depletion and amortization	2,162,350	1,732,142	1,665,962
(Gain) loss on sale/exchange of long-lived assets	(764,044)	17,445	(8,446)
Impairments	97,368	109,421	390,801
(Income) loss from investments	(76,039)	(7,596)	4,931
Loss on debt extinguishment	68,299	80	140,029
Share-based compensation expense	158,344	49,834	45,201
Distributions from equity method investments	66,200	18,693	50,220
Other	15,069	16,943	32,645
(Gain) loss on derivatives	(51,117)	(1,838,941)	4,642,932
Net cash settlements received (paid) on derivatives	1,217,895	900,650	(5,927,698)
Net premiums (paid) received on derivatives	(42,394)	(322,663)	14,200
Changes in other assets and liabilities:			
Accounts receivable	(220,446)	867,679	(168,978)
Accounts payable	16,512	(406,113)	181,459
Other current assets	(85,256)	93,787	48,576
Other items, net	7,385	(171,721)	38,172
Net cash provided by operating activities	2,826,973	3,178,850	3,465,560
Cash flows from investing activities:			
Capital expenditures	(2,253,709)	(2,019,037)	(1,400,443)
Cash paid for acquisitions, net of cash acquired	(874,265)	(2,271,881)	(205,347)
Proceeds from sale/exchange of assets	1,696,121	4,200	8,572
Proceeds from sale of investment shares	—	—	189,249
Capital contributions to equity method investments	(148,049)	(12,092)	(1,394)
Other investing activities	(80)	(14,845)	(12,390)
Net cash used in investing activities	(1,579,982)	(4,313,655)	(1,421,753)
Cash flows from financing activities:			
Proceeds from revolving credit facility borrowings	6,887,000	1,007,000	10,242,000
Repayment of revolving credit facility borrowings	(7,451,200)	(1,007,000)	(10,242,000)
Proceeds from issuance of debt	750,000	1,250,000	1,000,000
Proceeds from net settlement of Capped Call Transactions (Note 10)	93,290	—	—
Debt issuance costs	(18,854)	(5,336)	(26,506)
Repayment and retirement of debt	(4,313,867)	(1,015,836)	(917,039)
(Premiums paid) discounts received on debt extinguishment	(52,432)	5,178	(135,308)
Dividends paid	(326,581)	(228,339)	(203,629)
Repurchase and retirement of common stock	—	(201,029)	(409,485)
Net proceeds from the sale of units of the Midstream Joint Venture (Note 8)	3,410,392	—	—
Net (distribution to) contribution from noncontrolling interest	(1,640)	(7,322)	3,408
Cash paid for taxes to net settle share-based incentive awards	(102,872)	(41,780)	(24,773)
Other financing activities	889	1,602	14,206
Net cash used in financing activities	(1,125,875)	(242,862)	(699,126)
Net change in cash and cash equivalents	121,116	(1,377,667)	1,344,681
Cash and cash equivalents at beginning of year	80,977	1,458,644	113,963
Cash and cash equivalents at end of year	$ 202,093	$ 80,977	$ 1,458,644

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, 2024, 2023 and 2022

	Common Stock		Treasury Stock	(Accumulated Deficit) Retained Earnings	Accumulated Other Comprehensive Loss (a)	Noncontrolling Interest in Consolidated Subsidiaries	Total Equity
	Shares	Amount					
				(Thousands, except per share amounts)			
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 (Note 6)	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	419,896	$ 12,093,986	$ —	$ 2,681,898	$ (2,684)	$ 7,617	$ 14,780,817
Comprehensive income, net of tax:							
Net income				230,577		11,538	242,115
Other postretirement benefits liability adjustment, net of tax: $252					363		363
Dividends ($0.63 per share)				(327,237)			(327,237)
Share-based compensation plans	4,554	70,688					70,688
Convertible Notes settlements	19,992	285,608					285,608
Net settlement of Capped Call Transactions		93,290					93,290
Equitrans Midstream Merger (Note 6)	152,428	5,548,608				162,993	5,711,601
Change in ownership of consolidated subsidiary, net (Note 8)		(77,469)				3,500,000	3,422,531
Distribution to noncontrolling interest						(1,640)	(1,640)
Balance at December 31, 2024	596,870	$ 18,014,711	$ —	$ 2,585,238	$ (2,321)	$ 3,680,508	$ 24,278,136

Common shares authorized (in thousands): 640,000, 640,000 and 1,280,000. 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, 2024

1. Summary of Significant Accounting Policies

Nature of Operations. EQT Corporation is an integrated natural gas company with production, gathering and transmission operations focused in the Appalachian Basin.

In this Annual Report on Form 10-K, references to "EQT" refer to EQT Corporation and references to the "Company" refer collectively to EQT Corporation and its consolidated subsidiaries, collectively, in each case unless otherwise noted or indicated.

Principles of Consolidation and Noncontrolling Interests. The Consolidated Financial Statements include the accounts of EQT and all subsidiaries, ventures and partnerships in which EQT directly or indirectly holds a controlling interest and variable interest entities for which EQT is the primary beneficiary. Intercompany accounts and transactions have been eliminated in consolidation. The Company records noncontrolling interest in its Consolidated Financial Statements for any non-wholly-owned consolidated subsidiary.

Upon the completion of the Midstream Joint Venture Transaction (defined in Note 8) and as of December 31, 2024, the Company consolidates its controlling interest in the Midstream Joint Venture (defined in Note 8) under the voting interest entity model. See Note 8 for discussion of the formation of the Midstream Joint Venture, the completion of the Midstream Joint Venture Transaction and the method of allocation used in accounting for the portion of Midstream Joint Venture that is not owned by the Company.

In addition, upon the completion of the Equitrans Midstream Merger (defined in Note 6) and as of December 31, 2024, the Company consolidates its 60% interest in Eureka Midstream Holdings, LLC (Eureka Midstream Holdings), a joint venture that owns a gathering header pipeline system that is operated by a subsidiary of EQT, under the voting interest entity model. See Note 10 for discussion of the revolving credit facility of Eureka Midstream, LLC (Eureka), a wholly-owned subsidiary of Eureka Midstream Holdings.

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

Prior to the NEPA Gathering System Acquisition (defined in Note 6) and the First NEPA Non-Operated Asset Divestiture (defined in Note 7), the Company recorded in the Consolidated Financial Statements its pro rata share of revenues, expenses, assets and liabilities of the NEPA Gathering System (defined in Note 6). Following the completion of the First NEPA Non-Operated Asset Divestiture, the Company owns 100% of the NEPA Gathering System.

Segments. The Company has three reportable segments reflective of its three lines of business consisting of Production, Gathering and Transmission. See Note 2.

Reclassification. Certain previously reported amounts have been reclassified to conform to the current year presentation. In addition, as discussed further in Note 2, certain prior period amounts have been recast to reflect the Company's change in reportable segments from one reportable segment to three reportable segments consisting of Production, Gathering and Transmission.

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, Net of Allowance for Credit Losses. 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 3 for a discussion of amounts due from contracts with customers. 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.

Derivative Instruments. See Note 4 for a discussion of the Company's derivative instruments and Note 5 for a description of the fair value hierarchy and a discussion of the Company's fair value measurements.

Prepaid Expenses and Other. The following table summarizes the Company's prepaid expenses and other current assets.

	December 31, 2024	December 31, 2023
	(Thousands)	
Margin requirements with counterparties (see Note 4)	$ 86,975	$ 13,017
Prepaid expenses and other current assets	52,044	25,238
Total prepaid expenses and other	$ 139,019	$ 38,255

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

	December 31, 2024	December 31, 2023
	(Thousands)	
Oil and gas producing properties	$ 33,549,913	$ 32,510,595
Less: Accumulated depletion	12,489,317	10,734,099
Net oil and gas producing properties	21,060,596	21,776,496
Other production assets, at cost less accumulated depreciation	20,434	21,679
Net production assets	21,081,030	21,798,175
Gathering assets	8,067,556	1,153,049
Less: Accumulated depreciation	131,546	41,793
Net gathering assets	7,936,010	1,111,256
Transmission and storage assets	2,667,352	—
Less: Accumulated depreciation	30,027	—
Net transmission and storage assets	2,637,325	—
Other property, plant and equipment, at cost less accumulated depreciation	93,453	40,739
Net property, plant and equipment	$ 31,747,818	$ 22,950,170

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. In 2024, 2023 and 2022, the Company capitalized internal costs of approximately $69 million, $57 million and $48 million, respectively, to its oil and gas producing properties. In addition, in 2024, 2023 and 2022, the Company capitalized interest expense related to well development of approximately $54 million, $41 million and $28 million, 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 $0.90, $0.84 and $0.85 per Mcfe for the years ended December 31, 2024, 2023 and 2022, respectively.

There were no exploratory wells drilled during 2024, 2023 and 2022, and there were no capitalized exploratory well costs for the years ended December 31, 2024, 2023 and 2022.

The Company's gathering, transmission and storage property, plant and equipment is carried at cost. Maintenance projects that do not increase the overall life of the related assets are expensed as incurred. Expenditures that extend the useful life of the asset are capitalized. In 2024, the Company capitalized internal costs of approximately $25 million and $4 million to its gathering assets and transmission and storage assets, respectively. The Company's gathering, transmission and storage property, plant and equipment are depreciated using composite rates on a straight-line basis over the estimated useful life of the asset. The average depreciation rate for the year ended December 31, 2024 was 3.1%. Depreciation rates for the Company's regulated property, plant and equipment are reviewed when the Company files a change in transmission and storage rates with the FERC.

Impairment of Property, Plant and Equipment

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 2024, 2023 and 2022.

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, 2024, 2023 and 2022, the Company recorded $97.4 million, $109.4 million and $176.6 million, respectively, for impairment and expiration of leases. The Company's unproved properties had a net book value of approximately $1,563 million and $2,039 million as of December 31, 2024 and 2023, respectively.

Impairment of Other Property, Plant and Equipment. The Company evaluates its other property, plant and equipment for impairment when events or changes in circumstance indicate that the carrying value of such assets may not be recoverable. There were no indicators of impairment to the Company's asset groups identified during 2024, 2023 and 2022.

Impairment of Contract Asset. In 2020, the Company recorded a contract asset representing rate relief that the Company was entitled to pursuant to a consolidated gas gathering and compression agreement (the Consolidated GGA) entered into between the Company and an affiliate of EQM Midstream Partners, LP (EQM), which became an indirect wholly-owned subsidiary of EQT upon the closing of the Equitrans Midstream Merger. During 2022, the Company identified indicators that the carrying amount of its contract asset might not be fully recoverable, including increased uncertainty of the estimated timing of completion of the Mountain Valley Pipeline (the MVP) due to court rulings and public statements from Equitrans Midstream Corporation (Equitrans Midstream), the former parent of EQM, with respect to the completion of the MVP. As a result of the Company's impairment evaluation, the Company recognized impairment of the contract asset of $214 million in the Statement of Consolidated Operations for the year ended December 31, 2022, decreasing the contract asset's value to zero.

Investments in Unconsolidated Entities. See Note 11 for a discussion of the Company's investments in unconsolidated entities, which include EQT's equity method investments and investments in equity securities. The Company evaluates its investments in unconsolidated entities for impairment when events or changes in circumstances indicate that the investment's fair value is less than its carrying amount. The recognition of an impairment loss is required if the impairment is considered other than temporary. There were no indicators of impairment to the Company's investments in unconsolidated entities identified during 2024, 2023 and 2022.

Net Intangible Assets. As part of the Equitrans Midstream Merger preliminary purchase price allocation, the Company identified intangible assets related to certain of Equitrans Midstream's transmission services contracts. See Note 6. The Company evaluates its intangible assets for impairment when indicators of impairment are present. There were no indicators of impairment to the Company's net intangible assets identified during 2024.

Goodwill. Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business. Goodwill is allocated among, and evaluated for impairment at, the reporting unit level, which is defined as an operating segment or one level below an operating segment.

The Company evaluates its goodwill for impairment at least annually or more frequently if indicators of impairment exist. Goodwill is tested for impairment by assessing qualitative factors to determine whether it is more likely than not (greater than 50%) that the fair value of the reporting unit is less than the carrying amount or by performing a quantitative assessment. If the qualitative assessment indicates a possible impairment, then a quantitative impairment test is performed to determine the fair value of the reporting unit using a combination of an income and market approach. Otherwise, no further analysis is required.

Under the quantitative assessment, the evaluation of impairment involves comparing the current fair value of each reporting unit to its carrying value, including goodwill. In the event that the estimated fair value of a reporting unit is less than the carrying value, the Company would recognize an impairment loss equal to the excess of the reporting unit's carrying value over its fair value not to exceed the total amount of goodwill applicable to that reporting unit.

The Company evaluated its goodwill for impairment as of October 1, 2024 and determined there were no indicators of impairment.

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

	December 31,	
	2024	**2023**
	(Thousands)	
Accrued taxes other than income	$ 114,700	62,391
Accrued incentive compensation	53,138	24,542
Current portion of long-term capacity contracts	43,697	43,233
Current portion of lease liabilities	41,878	46,380
Deferred revenue	24,187	2,890
Accrued payroll	12,115	8,870
Other accrued liabilities	59,702	16,697
Total other current liabilities	$ 349,417	$ 205,003

Unamortized Debt Discount and Issuance Costs. Discounts and costs 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 10.

Leases. See Note 14 for a discussion of the Company's leases.

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.

EQM, Eureka Midstream Holdings and the Midstream Joint Venture are treated as partnerships for U.S. federal and applicable state income tax purposes and are not separately subject to U.S. federal or state income taxes. EQM's, Eureka Midstream Holdings' and the Midstream Joint Venture's income is included in the Company's pre-tax income; however, the Company does not record income tax expense on income attributable to noncontrolling interests in Eureka Midstream Holdings and the Midstream Joint Venture, which reduces the Company's effective tax rate in periods when the Company has consolidated pre-tax income and increases the effective tax rate in periods when the Company has consolidated pre-tax losses.

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 9.

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. In addition, in conjunction with the Equitrans Midstream Merger, the Company assumed a self-insured retention reserve for certain material losses related to excess liability and environmental liability for losses arising before December 20, 2024. The Company also assumed with the Equitrans Midstream Merger a 10% co-insurance related to material losses on property insurance coverage. Prospectively, coverage is included in the Company's insurance programs that do not have high self-insured and co-insurance amounts. Reserves are recorded on an undiscounted basis using analyses of historical data and, where applicable, actuarial estimates, which represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The reserves are reviewed by the Company quarterly and, where applicable, by independent actuaries annually.

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. In addition, the Company records asset retirement obligations on its storage wells with known plugging timelines. 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 gathering and transmission pipeline assets upon abandonment. In addition, the Company is responsible for the operation and maintenance of its gathering and transmission 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 gathering and transmission pipeline 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, 2024	December 31, 2023
	(Thousands)	
Balance at January 1	$ 911,057	$ 732,803
Accretion expense	68,501	47,700
Liabilities incurred	21,587	10,515
Liabilities settled	(66,729)	(33,938)
Liabilities assumed in acquisitions	45,847	64,424
Liabilities removed in divestitures	(28,701)	(6,480)
Change in estimates (a)	52,008	96,033
Balance at December 31	$ 1,003,570	$ 911,057

(a) During 2024, the Company recorded changes in estimates attributable primarily to increased plugging costs. During 2023, the Company recorded changes in estimates attributable primarily to inflation on estimated plugging costs.

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

Regulatory Accounting. As of December 31, 2024, the Company consolidates the Midstream Joint Venture, which holds Equitrans, L.P., which owns and operates the Midstream Joint Venture's wholly-owned FERC-regulated transmission and storage assets.

Through the rate-setting process, rate regulation allows recovery of costs to provide regulated services plus an allowed return on invested capital. Regulatory accounting allows deferral of costs and income as regulated assets and liabilities when it is probable that such costs and income is subject to recovery in future periods. Such deferred amounts are then recognized in Equitrans, L.P.'s Statement of Operations in the period in which the underlying costs and income are reflected in the rates charged by Equitrans, L.P. to shippers and operators. Equitrans, L.P. expects to continue to be subject to rate regulation.

The following table presents Equitrans, L.P.'s regulated operating revenues and expenses included in the Company's Consolidated Statement of Operations for the period from July 22, 2024 to December 31, 2024.

	July 22, 2024 to December 31, 2024
	(Thousands)
Operating revenues	$ 218,569
Operating expenses	$ 78,908

The following table presents Equitrans, L.P.'s regulated property, plant and equipment included in the Company's Consolidated Balance Sheet as of December 31, 2024.

	December 31, 2024
	(Thousands)
Property, plant and equipment	$ 2,667,352
Less: Accumulated depreciation	30,027
Net property, plant and equipment	$ 2,637,325

The Company includes Equitrans, L.P.'s regulated assets and liabilities in its Consolidated Balance Sheet. Equitrans, L.P.'s regulated assets are reported in other assets, and Equitrans, L.P.'s regulated liabilities are reported in other liabilities and credits. The following table summarizes Equitrans, L.P.'s regulated assets and liabilities as of December 31, 2024.

		December 31, 2024
		(Thousands)
Regulated assets:		
Deferred taxes (a)	$	142,757
Other recoverable costs (b)		23,182
Total regulated assets	$	165,939
Regulated liabilities:		
Deferred taxes (a)	$	8,534
Ongoing postretirement benefits other than pension and other reimbursable costs (c)		20,158
Total regulated liabilities	$	28,692

(a) The regulated asset from deferred taxes is related primarily to a historical deferred income tax position as well as taxes on the equity component of allowance for funds used during construction (AFUDC). The regulated liability from deferred taxes is related to the revaluation of a historical difference between the regulatory and tax bases of regulated property, plant and equipment. Equitrans, L.P. expects to recover the amortization of the deferred income tax positions ratably over the depreciable lives of the underlying assets. In addition, Equitrans, L.P. expects to recover the taxes on the equity component of AFUDC through future rates over the depreciable lives of the underlying long-lived assets.

(b) The regulated asset from other recoverable costs is related primarily to costs associated with Equitrans, L.P.'s asset retirement obligations, which Equitrans, L.P. expects to continue to recover over the next 9.5 years, and costs associated with a legacy postretirement benefits plan, which Equitrans, L.P. expects to continue to recover over the next 7.5 years.

(c) Equitrans, L.P. defers costs for other postretirement benefits plans, which are subject to recovery in approved rates. The related regulated liability reflects lower cumulative actuarial expenses than the amounts recovered through rates. Equitrans, L.P. expects to continue to recover costs as long as the existing recourse rates provide for recovery.

Revenue Recognition. For information on revenue recognition from contracts with customers, see Note 3. For information on gains and losses on derivative commodity instruments, see Note 4.

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 13 for a discussion of the Company's share-based compensation plans.

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

	Years Ended December 31,					
	2024		2023		2022	
			(Thousands)			
Transaction costs	$	309,419	$	56,263	$	14,185
Changes in legal and environmental reserves, including settlements		16,271		9,342	$	30,394
Other		24,174		18,438		12,752
Total other operating expenses	$	349,864	$	84,043	$	57,331

Defined Contribution Plan and Other Postretirement Benefits Plan. The Company recognized expense related to its defined contribution plan of $14.5 million, $9.0 million and $7.8 million for the years ended December 31, 2024, 2023 and 2022, respectively. In addition, the Company sponsors an other postretirement benefits plan.

Income Per Share. See Note 12 for a discussion of the Company's common stock and income per share computation.

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,		
	2024	**2023**	**2022**
		(Thousands)	
Cash paid during the year for:			
Interest, net of amount capitalized	$ 401,768	$ 213,141	$ 236,797
Income taxes, net	7,960	13,350	20,773
Non-cash activity during the period for:			
Equity issued as consideration for acquisitions (Note 6)	$ 5,548,608	$ 2,152,631	$ —
Issuance of EQT common stock for Convertible Notes settlement (Note 10)	285,608	122,830	63
First NEPA Non-Operated Asset Divestiture (Note 7)	155,318	—	—
Increase in asset retirement costs and obligations	73,576	106,548	54,608
Increase in right-of-use assets and lease liabilities, net	29,568	45,774	23,356
Capitalization of non-cash equity share-based compensation	10,095	6,287	5,406
Investments in nonconsolidated entities	3,428	—	—
Accrued transaction costs related to the sale of units of the Midstream Joint Venture (Note 8)	1,135	—	—
Dissolution of consolidated variable interest entity	—	25,227	—

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 annual reporting periods beginning after December 15, 2023 and interim periods within annual reporting periods beginning after December 15, 2024. The Company adopted ASU 2023-07 in the fourth quarter of 2024. See Note 2 for segments disclosures.

In December 2023, the FASB issued ASU 2023-09, *Income Taxes: Improvements to Income Tax Disclosures,* to improve 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 annual reporting periods 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.

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses*, to improve the disclosures about a public business entity's expenses and address requests from investors for more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation, amortization and depletion) in commonly presented expense captions (such as cost of sales; selling, general and administrative expense; and research and development). This ASU is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The requirements should be applied prospectively with the option for retrospective application. The Company is evaluating the impact ASU 2024-03 will have on its financial statements and related disclosures.

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

2. Financial Information by Business Segment

Prior to the completion of the Equitrans Midstream Merger, the Company's operations consisted of one reportable segment. Historically, the Company administered all properties as a whole rather than by discrete operating segments and measured financial performance as a single enterprise and not on an area-by-area basis.

As a result of the completion of the Equitrans Midstream Merger, the Company adjusted its internal reporting structure and the Company's chief operating decision maker, Toby Rice, President and Chief Executive Officer, changed the manner in which he measures financial performance and allocates resources to incorporate the gathering and transmission assets acquired by the Company in the Equitrans Midstream Merger. Hence, the Company's operations expanded to comprise three discrete operating segments reflective of its three lines of business consisting of Production, Gathering and Transmission.

The Company's Production segment comprises the Company's natural gas, NGLs and oil extraction, development and production business and supporting ventures, such as water operations. The Company's Gathering segment owns and operates the Company's gathering system, which has extensive overlap with the Company's Production segment operations, and processing facility. The Company's Transmission segment operates the Company's FERC-regulated, interstate transmission and storage system, which has multiple interconnect points to other interstate pipelines and local distribution companies. In addition, the Transmission segment holds the Company's investment in the MVP Joint Venture (defined in Note 11). Certain amounts, including cash and cash equivalents, debt, income taxes and other amounts related to the Company's headquarters function as well as amounts related to the Company's energy transition initiatives are managed on a consolidated basis and, as such, have not been allocated to the Company's segments and have been presented as "Other."

As a result of the Company's change in reportable segments from one reportable segment to three reportable segments, certain prior period amounts have been recast.

The accounting policies of the Company's segments are the same as those described in Note 1.

For all of the Company's segments, the chief operating decision maker uses operating income as the profitability metric to measure financial performance and allocate resources. The chief operating decision maker considers actual-to-forecast variances for operating income when allocating capital and personnel to the Company's segments and compares operating income and return on assets of each segment to assess segment performance. In addition to operating income, the chief operating decision maker reviews equity earnings recognized from, and the carrying value of the Company's investment in, the MVP Joint Venture when measuring the financial performance of, and allocating resources to, the Company's Transmission segment.

Substantially all of the Company's operating revenues and assets are generated and located in the United States.

Total segment operating income. The follow tables present the Company's profit and loss metric of operating income by segment.

	Year Ended December 31, 2024					
	Production	Gathering	Transmission	Total Segment	Intersegment eliminations and other	EQT Corporation
	(Thousands)					
Operating revenues:						
Sales of natural gas, natural gas liquids and oil	$ 4,934,366	$ —	$ —	$ 4,934,366	$ —	$ 4,934,366
Gain (loss) on derivatives	67,880	(16,763)	—	51,117	—	51,117
Pipeline, net marketing services and other	7,587	766,463	218,293	992,343	(704,517)	287,826
Total operating revenues	5,009,833	749,700	218,293	5,977,826	(704,517)	5,273,309
Operating expenses (a):						
Transportation and processing	2,619,710	—	—	2,619,710	(704,094)	1,915,616
Production	377,007	—	—	377,007	—	377,007
Operating and maintenance	—	89,897	20,496	110,393	—	110,393
Exploration	2,735	—	—	2,735	—	2,735
Selling, general and administrative (b)	244,450	38,837	17,183	300,470	36,254	336,724
Depreciation, depletion and amortization	2,016,670	89,513	39,406	2,145,589	16,761	2,162,350
(Gain) loss on sale/ exchange of long-lived assets	(764,431)	(22)	409	(764,044)	—	(764,044)
Impairment and expiration of leases	97,368	—	—	97,368	—	97,368
Other operating expenses (c)	12,696	—	—	12,696	337,168	349,864
Total operating expenses	4,606,205	218,225	77,494	4,901,924	(313,911)	4,588,013
Operating income (loss)	$ 403,628	$ 531,475	$ 140,799	$ 1,075,902	$ (390,606)	$ 685,296

(a) The significant expense categories and amounts presented align with information that is regularly provided to the chief operating decision maker.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast as the necessary information is not available and the cost to develop such information would be excessive.

(c) Corporate other operating expenses consisted primarily of transaction costs related to the Equitrans Midstream Merger. See Note 1 for a summary of the Company's consolidated other operating expenses.

	Year Ended December 31, 2023				
	Production	Gathering	Total Segment	Intersegment eliminations and other	EQT Corporation
			(Thousands)		
Operating revenues:					
Sales of natural gas, natural gas liquids and oil	$ 5,044,768	$ —	$ 5,044,768	$ —	$ 5,044,768
Gain on derivatives	1,838,941	—	1,838,941	—	1,838,941
Pipeline, net marketing services and other	12,649	161,395	174,044	(148,830)	25,214
Total operating revenues	6,896,358	161,395	7,057,753	(148,830)	6,908,923
Operating expenses (a):					
Transportation and processing	2,306,090	—	2,306,090	(148,830)	2,157,260
Production	239,001	—	239,001	—	239,001
Operating and maintenance	—	15,699	15,699	—	15,699
Exploration	3,330	—	3,330	—	3,330
Selling, general and administrative (b)	236,171	—	236,171	—	236,171
Depreciation, depletion and amortization	1,705,311	17,066	1,722,377	9,765	1,732,142
Loss on sale/exchange of long-lived assets	17,445	—	17,445	—	17,445
Impairment and expiration of leases	109,421	—	109,421	—	109,421
Other operating expenses (c)	9,177	—	9,177	74,866	84,043
Total operating expenses	4,625,946	32,765	4,658,711	(64,199)	4,594,512
Operating income (loss)	$ 2,270,412	$ 128,630	$ 2,399,042	$ (84,631)	$ 2,314,411

(a) The significant expense categories and amounts presented align with information that is regularly provided to the chief operating decision maker.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast as the necessary information is not available and the cost to develop such information would be excessive.

(c) Corporate other operating expenses consisted primarily of transaction costs related to the Tug Hill and XcL Midstream Acquisition (defined in Note 6). See Note 1 for a summary of the Company's consolidated other operating expenses.

	Year Ended December 31, 2022				
	Production	Gathering	Total Segment	Intersegment eliminations and other	EQT Corporation
			(Thousands)		
Operating revenues:					
Sales of natural gas, natural gas liquids and oil	$ 12,114,168	$ —	$ 12,114,168	$ —	$ 12,114,168
Loss on derivatives	(4,642,932)	—	(4,642,932)	—	(4,642,932)
Pipeline, net marketing services and other	12,827	96,947	109,774	(83,321)	26,453
Total operating revenues	7,484,063	96,947	7,581,010	(83,321)	7,497,689
Operating expenses (a):					
Transportation and processing	2,200,297	—	2,200,297	(83,321)	2,116,976
Production	298,388	—	298,388	—	298,388
Operating and maintenance	—	2,597	2,597	—	2,597
Exploration	3,438	—	3,438	—	3,438
Selling, general and administrative (b)	252,645	—	252,645	—	252,645
Depreciation, depletion and amortization	1,648,808	8,035	1,656,843	9,119	1,665,962
Gain on sale/exchange of long-lived assets	(8,446)	—	(8,446)	—	(8,446)
Impairment and expiration of leases	176,606	—	176,606	—	176,606
Impairment of contract asset	214,195	—	214,195	—	214,195
Other operating expenses (c)	32,605	—	32,605	24,726	57,331
Total operating expenses	4,818,536	10,632	4,829,168	(49,476)	4,779,692
Operating income (loss)	$ 2,665,527	$ 86,315	$ 2,751,842	$ (33,845)	$ 2,717,997

(a) The significant expense categories and amounts presented align with information that is regularly provided to the chief operating decision maker.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast as the necessary information is not available and the cost to develop such information would be excessive.

(c) Corporate other operating expenses consisted primarily of transaction costs related to the Tug Hill and XcL Midstream Acquisition. See Note 1 for a summary of the Company's consolidated other operating expenses.

Reconciliation of total segment operating income to income before income taxes

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Total segment operating income	$ 1,075,902	$ 2,399,042	$ 2,751,842
Intersegment eliminations	457	—	—
Unallocated amounts:			
Other revenue	(34)	—	—
Corporate selling, general and administrative	36,254	—	—
Corporate other depreciation and amortization	16,761	9,765	9,119
Corporate other operating expenses (a)	337,168	74,866	24,726
(Income) loss from investments (b)	(76,039)	(7,596)	4,931
Other income	(25,983)	(1,231)	(11,280)
Loss on debt extinguishment	68,299	80	140,029
Interest expense, net	454,825	219,660	249,655
Income before income taxes	$ 264,194	$ 2,103,498	$ 2,334,662

(a) Corporate other operating expenses consisted primarily of transaction costs related to the Equitrans Midstream Merger for the year ended December 31, 2024. Corporate other operating expenses consisted primarily of transaction costs related to the Tug Hill and XcL Midstream Acquisition for both years ended December 31, 2023 and 2022. See Note 1 for a summary of the Company's consolidated other operating expenses.

(b) Income from investments for the year ended December 31, 2024 included $78.8 million of equity earnings from the Company's investment in the MVP Joint Venture, which is reported in the Company's Transmission segment.

Total segment assets. The following table presents the Company's total assets by segment. The Company's investment in the MVP Joint Venture is presented in investments in unconsolidated entities in the Consolidated Balance Sheet. The Company did not have an investment in the MVP Joint Venture or goodwill prior to completion of the Equitrans Midstream Merger.

	Production	Gathering	Transmission	Total Segment
December 31, 2024		(Thousands)		
Investment in the MVP Joint Venture	$ —	$ —	$ 3,534,730	$ 3,534,730
Goodwill	—	—	1,217,742	1,217,742
Other segment assets	22,546,098	8,295,625	2,919,532	33,761,255
Total assets	$ 22,546,098	$ 8,295,625	$ 7,672,004	$ 38,513,727
December 31, 2023				
Total assets	$ 23,803,913	$ 1,215,627	$ —	$ 25,019,540
December 31, 2022				
Total assets	$ 20,469,506	$ 417,117	$ —	$ 20,886,623

Reconciliation of total segment assets to total assets

	December 31,		
	2024	2023	2022
		(Thousands)	
Total segment assets	$ 38,513,727	$ 25,019,540	$ 20,886,623
Intersegment eliminations	(318,835)	(47,471)	(19,288)
Unallocated amounts:			
Cash and cash equivalents	202,093	80,977	1,458,644
Income tax receivable	97,378	91,414	—
Other property, plant and equipment, at cost less accumulated depreciation	93,453	40,739	32,594
Goodwill (a)	861,739	—	—
Regulated asset from deferred taxes	142,757	—	—
Other	237,943	99,899	311,353
Total assets	$ 39,830,255	$ 25,285,098	$ 22,669,926

(a) Represents goodwill attributable to additional deferred tax liabilities that arose from the differences between the fair value and tax bases of the Equitrans Midstream Merger preliminary purchase price allocation that carried over from Equitrans Midstream to the Company. See Note 6.

Total segment capital expenditures. The following table presents the Company's capital expenditures by segment.

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Production	$ 2,003,635	$ 1,878,417	$ 1,427,995
Gathering	202,264	31,701	6,155
Transmission	31,446	—	—
Total segment capital expenditures	2,237,345	1,910,118	1,434,150
Other corporate items	28,603	15,125	5,962
Total capital expenditures	$ 2,265,948	$ 1,925,243	$ 1,440,112

Consolidated GGA

Pursuant to the terms of the Consolidated GGA, EQM's affiliate, which is party thereto (which is included, post-Equitrans Midstream Merger, in the Company's Gathering segment) (the EQM Affiliate) agreed to provide gas gathering services to a subsidiary of EQT (which is included in the Company's Production segment) (the EQT Party) and the EQT Party committed to an initial annual minimum volume commitment (MVC) of 3.0 Bcf per day and an acreage dedication in Pennsylvania and West Virginia. The Consolidated GGA is effective through December 31, 2035 and will renew annually thereafter unless terminated by the parties thereto.

The Consolidated GGA provided for cash bonus payments (the Henry Hub Cash Bonus) conditioned upon the quarterly average of the NYMEX Henry Hub natural gas settlement price exceeding certain price thresholds to be payable by the EQT Party to the EQM Affiliate during each quarter beginning with the first day of the quarter in which the MVP In-Service Date (as defined in the Consolidated GGA) occurs and ending on the earlier of 36 months thereafter or December 31, 2024. Upon commencement of long-term firm capacity obligations, the MVP In-Service Date occurred on July 1, 2024.

The Company's Production and Gathering segments recorded their respective derivative liability and asset and any gain or loss related to the Henry Hub Cash Bonus. During the fourth quarter of 2024, the EQT Party paid $4.2 million to the EQM Affiliate, and, as of December 31, 2024, the derivative related to the Henry Hub Cash Bonus was settled. As of December 31, 2023, the derivative related to the Henry Hub Cash Bonus had a fair value of approximately $48 million. The fair value of the derivative asset and liability related to the Henry Hub Cash Bonus was based on significant inputs that are interpolated from observable market data and, as such, was a Level 2 fair value measurement. See Note 5 for a description of the fair value hierarchy.

3. Revenue from Contracts with Customers

Sales of natural gas, NGLs and oil. 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 Company allocates the fixed consideration 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.

Pipeline revenue. The Company provides gathering, transmission and storage services under firm and interruptible service contracts.

Firm service contracts generally require the customer to pay a firm reservation fee, which is a fixed, monthly charge to reserve an agreed upon amount of pipeline or storage capacity regardless of whether the customer uses the capacity. Under its firm service contracts, the Company has a stand-ready obligation to provide the firm service over the life of the contract. The performance obligation for revenue from firm reservation fees is satisfied over time as the pipeline capacity is made available to the customer. As such, the Company recognizes firm reservation fee revenue evenly over the contract period using a time-elapsed output method to measure progress.

Volumetric-based fees, which are charges based on the volume of gas gathered, transported or stored, can also be charged under firm service contracts for each firm contracted volume gathered, transported or stored as well as for volumes gathered, transported or stored in excess of the firm contracted volume so long as capacity exists.

Interruptible service contracts require the customer to pay volumetric-based fees and generally do not guarantee access to the pipeline or storage facility.

The performance obligation for revenue from volumetric-based fees is generally satisfied upon the Company's monthly invoicing to the customer for volumes gathered, transported or stored during the month. The amount invoiced generally corresponds directly to the value of the Company's performance to date as the customer obtains value as each volume is gathered, transported or stored. Gathering service contracts are invoiced on a one-month lag, with payment typically due within 21 days of the invoice date. Revenue for gathering services provided but not yet invoiced is estimated based on contract data, preliminary throughput and allocation measurements on a monthly basis. Transmission and storage service contracts are invoiced at the end of each calendar month, with payment typically due within 10 days of the invoice date.

For both firm reservation and volumetric-based fee revenues, the Company allocates the transaction price to each performance obligation based on the estimated relative standalone selling price. Any excess of consideration received over revenue recognized results in the deferral of those amounts until future periods based on a units-of-production or straight-line methodology as these methods align with the consumption of services provided to the customer. The units-of-production methodology requires the use of judgment to estimate future production volumes.

Certain of the Company's gathering service agreements are structured with MVCs, which specify minimum quantities that the customer will be charged regardless of whether such quantities are gathered. Revenue is recognized for MVCs when the performance obligation has been met, which is the earlier of when the gas is gathered or when the likelihood that the customer will be able to meet its MVC is remote. If a customer fails to meet its MVC for a specified period (thus not exercising all the contractual rights to gathering services within the specified period), the customer is obligated to pay a contractually-determined fee based on the shortfall between actual volume gathered and the MVC.

Disaggregated revenue information. 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 pipeline, net marketing services and other revenues in the Statements of Consolidated Operations. Derivative contracts are also outside the scope of ASU 2014-09.

	Years Ended December 31,		
	2024	**2023**	**2022**
		(Thousands)	
Revenues from contracts with customers:			
Production:			
Sales of natural gas, NGLs and oil			
Natural gas sales	$ 4,224,882	$ 4,520,817	$ 11,448,293
NGLs sales	615,933	427,760	586,715
Oil sales	93,551	96,191	79,160
Sales of natural gas, NGLs and oil	4,934,366	5,044,768	12,114,168
Gathering:			
Pipeline revenue			
Firm reservation fee revenue (a)	313,987	—	—
Volumetric-based fee revenue (b)	452,476	161,395	96,947
Total	766,463	161,395	96,947
Transmission:			
Pipeline revenues			
Firm reservation fee revenue	183,088	—	—
Volumetric-based fee revenue	34,968	—	—
Total	218,056	—	—
Intersegment eliminations and other	(704,517)	(148,830)	(83,321)
Total revenues from contracts with customers (c)	5,214,368	5,057,333	12,127,794
Other sources of revenue:			
Gain (loss) on derivatives	51,117	1,838,941	(4,642,932)
Net marketing services and other revenues	7,824	12,649	12,827
Total other sources of revenue	58,941	1,851,590	(4,630,105)
Total operating revenues	$ 5,273,309	$ 6,908,923	$ 7,497,689

(a) Firm reservation fee revenue for the year ended December 31, 2024 included unbilled revenues supported by MVCs of $4.2 million.
(b) Volumetric-based fee revenue for the year ended December 31, 2024 included unbilled revenues supported by MVCs of $4.5 million.
(c) 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 $939.9 million and $584.8 million in accounts receivable in the Consolidated Balance Sheets as of December 31, 2024 and 2023, respectively.

Summary of remaining performance obligations. The following table summarizes the transaction price allocated to the Company's remaining obligations on all contracts with fixed consideration as of December 31, 2024. The table excludes contracts that qualified for the exception to the relative standalone selling price method as of December 31, 2024.

	2025	2026	2027	2028	2029	Thereafter	Total
				(Thousands)			
Gathering firm reservation fees:							
Third-party contracts	$ 101,671	$ 92,311	$ 85,651	$ 85,651	$ 85,651	$ 371,792	$ 822,727
Affiliate contracts	91,918	101,728	101,393	97,701	97,701	1,482,452	1,972,893
Total Gathering firm reservation fees	193,589	194,039	187,044	183,352	183,352	1,854,244	2,795,620
Gathering revenues supported by MVCs:							
Third-party contracts	82,396	89,217	80,904	77,153	65,788	185,423	580,881
Affiliate contracts	372,446	397,966	410,621	411,740	410,621	2,042,451	4,045,845
Total Gathering revenues supported by MVCs	454,842	487,183	491,525	488,893	476,409	2,227,874	4,626,726
Transmission firm reservation fees:							
Third-party contracts	176,189	174,435	171,768	169,410	166,324	814,742	1,672,868
Affiliate contracts	241,507	261,045	261,045	260,715	260,383	1,964,638	3,249,333
Total Transmission firm reservation fees	417,696	435,480	432,813	430,125	426,707	2,779,380	4,922,201
Total	$ 1,066,127	$ 1,116,702	$ 1,111,382	$ 1,102,370	$ 1,086,468	$ 6,861,498	$12,344,547

As of December 31, 2024, the Company had no remaining performance obligations on its natural gas sales contracts with fixed consideration.

In addition, based on total projected contractual revenues, the Company's firm gathering third-party contracts and firm transmission and storage third-party contracts had a weighted average remaining term of approximately 10 years and 11 years, respectively, as of December 31, 2024. Based on total projected contractual revenues, the Company's firm gathering affiliate contracts and firm transmission and storage affiliate contracts had a weighted average remaining term of approximately 14 years and 13 years, respectively, as of December 31, 2024.

4. 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 result in 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 2,189 billion cubic feet (Bcf) of natural gas and 2,562 thousand barrels (Mbbl) of NGLs as of December 31, 2024 and 2,045 Bcf of natural gas and 1,049 Mbbl of NGLs as of December 31, 2023. The open positions at both December 31, 2024 and 2023 had maturities extending through December 2027.

Certain of the Company's OTC derivative instrument contracts provide that, if EQT'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, 2024, EQT'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, 2024 and 2023, the aggregate fair value of the Company's OTC derivative instruments with credit rating risk-related contingent features in a net liability position was $61.9 million and $6.4 million, respectively, for which no deposits were required or recorded in the Consolidated Balance Sheets.

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, 2024 and 2023, 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, 2024 and 2023, there were $87.0 million and $13.0 million, respectively, of such deposits recorded as a current asset 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
December 31, 2024		(Thousands)		
Asset derivative instruments, at fair value	$ 143,581	$ (117,350)	$ —	$ 26,231
Liability derivative instruments, at fair value	446,519	(117,350)	(86,975)	242,194
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

5. 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 EQT's or the 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.

		Fair value measurements at reporting date using:		
	Gross derivative instruments recorded in the Consolidated Balance Sheets	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2024		(Thousands)		
Asset derivative instruments, at fair value	$ 143,581	$ 50,300	$ 93,281	$ —
Liability derivative instruments, at fair value	446,519	81,074	365,445	—
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	—

The carrying value of cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. The carrying value of borrowings under EQT's revolving credit facility, Eureka's revolving credit facility and (prior to its redemption) the Term Loan Facility (defined in Note 10) approximates fair value as each facility's interest rate is 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, 2024 and 2023, the Company's senior notes had a fair value of approximately $8.8 billion and $4.9 billion, respectively, and a carrying value of approximately $8.9 billion and $4.5 billion, respectively, inclusive of any current portion. See Note 10 for further discussion of the Company's debt.

Upon the closing of the Equitrans Midstream Merger, EQT's note payable to EQM became an intercompany transaction on a consolidated basis and, as such, was effectively settled on July 22, 2024. See Note 6. As of December 31, 2023, the fair value of EQT's note payable to EQM was estimated using an income approach model with a market-based discount rate and was considered a Level 3 fair value measurement. As of December 31, 2023, EQT's note payable to EQM had a fair value and carrying value of approximately $91 million and $88 million, respectively, inclusive of any current portion.

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 1 for a discussion of the fair value measurement and impairment of the Company's property, plant equipment. In addition, see Note 1 for a discussion of impairment of the Company's contract asset, investments in unconsolidated entities, net intangible assets and goodwill. See Note 1 for a discussion of the fair value measurement of the Company's asset retirement obligations. See Note 2 for a discussion of the fair value measurement of the Henry Hub Cash Bonus. See Note 6 for a discussion of the fair value measurement of assets acquired and liabilities assumed in the Equitrans Midstream Merger. See Note 7 for a discussion of the fair value measurement of the assets received as consideration for the First NEPA Non-Operated Asset Divestiture. See Note 11 for a discussion of the fair value measurement of the Company's investment in the Investment Fund (defined in Note 11).

6. Acquisitions

Equitrans Midstream Merger

On July 22, 2024, the Company completed its acquisition of Equitrans Midstream (Equitrans Midstream Merger) pursuant to the agreement and plan of merger dated March 10, 2024 (the Merger Agreement), by and among EQT, Humpty Merger Sub Inc., an indirect wholly-owned subsidiary of EQT (Merger Sub), Humpty Merger Sub LLC, an indirect wholly-owned subsidiary of EQT (LLC Sub), and Equitrans Midstream.

Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub merged with and into Equitrans Midstream (the First Merger), with Equitrans Midstream surviving as an indirect wholly-owned subsidiary of EQT (the First Step Surviving Corporation), and, as the second step in a single integrated transaction with the First Merger, the First Step Surviving Corporation merged with and into LLC Sub (the Second Merger and, together with the First Merger, the Equitrans Midstream Merger), with LLC Sub surviving the Second Merger as an indirect wholly-owned subsidiary of EQT.

Upon the closing of the Equitrans Midstream Merger, each share of common stock, no par value, of Equitrans Midstream (Equitrans Midstream common stock) that was issued and outstanding immediately prior to the effective time of the First Merger (other than shares of Equitrans Midstream common stock owned by Equitrans Midstream or its subsidiaries or by the Company) was converted into the right to receive, without interest, 0.3504 shares of EQT common stock, which totaled 152,427,848 shares of EQT common stock with an aggregate value of $5.5 billion, based on an EQT common stock share price of $35.88. In addition, in connection with the closing of the Equitrans Midstream Merger, the Company paid an aggregate of $79.5 million of equity consideration to employees of Equitrans Midstream who did not continue with the Company upon the Equitrans Midstream Merger closing date.

Immediately prior to the completion of the Equitrans Midstream Merger, on July 22, 2024, using borrowings under EQT's revolving credit facility, the Company paid $685.3 million to effect the purchase and redemption of all of the issued and outstanding Series A Perpetual Convertible Preferred Shares, no par value, of Equitrans Midstream (the Equitrans Midstream preferred stock).

Immediately following the closing of the Equitrans Midstream Merger, on July 22, 2024, EQM repaid all of its outstanding obligations under EQM's revolving credit facility using cash on hand and cash contributions from EQT, and, thereafter, EQM terminated its revolving credit facility. See Note 10.

Upon completion of the Equitrans Midstream Merger, the pre-existing contractual relationships between the Company, as producer, and Equitrans Midstream, as gathering and transmission services provider, are treated as intercompany transactions on a consolidated basis and, as such, were effectively settled on July 22, 2024. Likewise, upon completion of the Equitrans Midstream Merger, EQT's note payable to EQM became an intercompany transaction on a consolidated basis and, as such, was effectively settled on July 22, 2024.

For the year ended December 31, 2024, the Company recognized $304.8 million of transaction costs related to the Equitrans Midstream Merger in other operating expenses in the Statement of Consolidated Operations. Included in such transaction costs was severance and other termination benefits and stock-based compensation costs of $165.4 million, of which $60.8 million was cash and $104.6 million was non-cash.

Allocation of Purchase Price. The Equitrans Midstream Merger 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 July 22, 2024 with the excess of purchase price over estimated fair value of the identified net assets recognized as goodwill. 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 and final income tax computations. 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	$	5,548,608
Cash (paid in lieu of fractional shares)		29
Redemption of Equitrans Midstream preferred stock		685,337
Settlement of pre-existing relationships		(239,741)
Total consideration	$	5,994,233
Fair value of assets acquired:		
Cash and cash equivalents	$	58,767
Accounts receivable, net		82,072
Income tax receivable		2,142
Prepaid expenses and other		22,048
Property, plant and equipment		9,379,642
Investments in unconsolidated entities		3,363,336
Net intangible assets		200,000
Other assets		249,846
Noncontrolling interest in consolidated subsidiaries		(162,993)
Amount attributable to assets acquired	$	13,194,860
Fair value of liabilities assumed:		
Current portion of debt	$	699,837
Accounts payable		65,006
Accrued interest		47,996
Other current liabilities		70,951
Revolving credit facility borrowings		1,035,000
Senior notes		6,273,941
Deferred income taxes		935,106
Other liabilities and credits		152,271
Amount attributable to liabilities assumed	$	9,280,108
Goodwill	$	2,079,481

The fair value of Equitrans Midstream's property, plant and equipment, which primarily includes gathering, transmission and storage systems and water infrastructure assets, and Equitrans Midstream's equity method investment in the MVP Joint Venture was measured using a combination of a cost and income approach based on inputs that are not observable in the market and, as such, are Level 3 fair value measurements. Significant inputs to the valuation of Equitrans Midstream's property, plant and equipment and investment in the MVP Joint Venture include replacement costs for similar assets, relative age of the assets, any potential economic or functional obsolescence associated with the assets, future revenue estimates and future operating cost assumptions and estimated weighted average costs of capital.

The fair value of the noncontrolling interest in Eureka Midstream Holdings was calculated using the noncontrolling interest ownership percentage and the enterprise value of Eureka Midstream Holdings, which was measured using a combination of a cost and income approach based on inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. Significant inputs to the valuation of the noncontrolling interest in Eureka Midstream Holdings include replacement costs for similar assets, relative age of the assets, any potential economic or functional obsolescence associated with the assets, future revenue estimates, future operating cost assumptions and estimated weighted average cost of capital.

As part of the preliminary purchase price allocation, the Company identified intangible assets related to certain of Equitrans Midstream's transmission services contracts. The fair value of the identified intangible assets was determined using the income approach based on inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. Significant inputs to the valuation of the identified intangible assets include future revenue estimates, future cost assumptions, estimated contract renewals, a discount rate assumption and an estimated required rate of return on the assets. The identified intangible assets are amortized over their useful life of 15 years on a straight-line basis, which reflects the pattern in which the Company expects to consume the economic benefits of the assets. The estimated annual amortization expense for the intangible assets is $13.3 million for each of the next 5 years.

The fair value of EQM's senior notes was measured using established fair value methodology. Because not all of EQM's senior notes are actively traded, their fair value is a Level 2 fair value measurement. The difference between the fair value and principal amount of the assumed senior notes is amortized over the remaining life of the debt. The unamortized amount is presented as a reduction of debt in the Consolidated Balance Sheet. Because the carrying value of borrowings under EQM's revolving credit facility and Eureka's revolving credit facility approximated their respective fair value (as each facility's interest rate is based on prevailing market rates), the Company considers their fair values to be Level 1 fair value measurements.

Goodwill is attributable to the Company's qualitative assumptions of long-term value that the Equitrans Midstream Merger creates for EQT shareholders. Of the total goodwill, the Company attributed $1.2 billion to the vertical integration of the business, including from the elimination of contracted transportation costs with Equitrans Midstream as the Company is unable to recognize intangible assets related to its significant long-term customer contracts with Equitrans Midstream as such contracts became intercompany transactions upon the closing of the Equitrans Midstream Merger. The Company allocated this amount of total goodwill to its Transmission segment. In addition, the Company attributed $0.9 billion of total goodwill to additional deferred tax liabilities that arose from the differences between the fair value and tax bases of preliminary purchase price allocation that carried over from Equitrans Midstream to the Company. Given the income tax characteristics of EQM (the entity that holds the gathering and transmission operations acquired in the Equitrans Midstream Merger) the Company presents this amount of total goodwill as "Other" for segments reporting. See Note 2. Differences between the preliminary purchase price allocation and the final purchase price allocation may change the amount of goodwill recognized.

In conjunction with the Equitrans Midstream Merger, as of the Equitrans Midstream Merger closing date, the Company had unamortized carryover tax basis of $647.2 million of tax deductible goodwill.

See Note 5 for a description of the fair value hierarchy.

Post-Acquisition Operating Results. The table below summarizes amounts contributed by the assets acquired in the Equitrans Midstream Merger, inclusive of intercompany eliminations, to the Company's consolidated results for the period beginning on July 22, 2024 and ending on December 31, 2024.

	July 22, 2024 through December 31, 2024	
	(Thousands)	
Loss on derivatives	$	(16,763)
Pipeline, net marketing services and other		274,646
Total operating revenues	$	257,883
Net loss (a)	$	(136,946)
Less: Net income attributable to noncontrolling interests		12,879
Net loss attributable to EQT Corporation	$	(149,825)

(a) Net loss includes $280.6 million of transaction costs related to the Equitrans Midstream Merger.

Unaudited Pro Forma Information. The table below summarizes the Company's results as though the Equitrans Midstream Merger had been completed on January 1, 2023. Certain historical amounts were reclassified to conform to the Company's current 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 Equitrans Midstream Merger occurred on January 1, 2023 nor are they indicative of future consolidated results of operations.

	Years Ended December 31,			
	2024		2023	
	(Thousands, except per share amounts)			
Pro forma operating revenues:				
Pro forma sales of natural gas, NGLs and oil	$	4,934,366	$	5,044,768
Pro forma gain on derivatives		17,685		1,887,016
Pro forma pipeline, net marketing services and other		621,214		616,245
Pro forma total operating revenues	$	5,573,265	$	7,548,029
Pro forma net income (a)	$	489,503	$	2,439,515
Less: Pro forma net income attributable to noncontrolling interests		28,303		30,037
Pro forma net income attributable to EQT Corporation	$	461,200	$	2,409,478
Pro forma income per share of common stock attributable to EQT Corporation:				
Pro forma net income attributable to EQT Corporation – Basic	$	0.78	$	4.52
Pro forma net income attributable to EQT Corporation – Diluted	$	0.77	$	4.27

(a) Pro forma net income for the year ended December 31, 2024 includes $304.8 million of transaction costs related to the Equitrans Midstream Merger.

NEPA Gathering System Acquisition

In 2021, the Company acquired a 50% interest in and became the operator of certain gathering assets located in Northeast Pennsylvania (collectively, the NEPA Gathering System).

On April 11, 2024, the Company completed its acquisition of a minority equity partner's 33.75% interest in the NEPA Gathering System for a purchase price of approximately $205 million (the NEPA Gathering System Acquisition), subject to customary post-closing adjustments. The NEPA Gathering System Acquisition was accounted for as an asset acquisition, and, as such, its purchase price was allocated to property, plant and equipment.

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 and the gathering and processing assets from THQ-XcL Holdings I, LLC 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. The purchase price for the Tug Hill and XcL Midstream Acquisition consisted of 49,599,796 shares of EQT common stock and approximately $2.4 billion in cash, subject to customary post-closing adjustments.

The Company accounted for the Tug Hill and XcL Midstream Acquisition as a business combination using the acquisition method. The Company completed the purchase price allocation for the Tug Hill and XcL Midstream Acquisition during the first quarter of 2024. The purchase accounting adjustments recorded in 2024 were not material.

For the years ended December 31, 2024 and 2023, the Company recognized $4.4 million and $56.3 million, respectively, of transaction costs related to the Tug Hill and XcL Midstream Acquisition in other operating expenses in the Statements of Consolidated Operations.

2022 Asset Acquisition

In the fourth quarter of 2022, the Company completed its acquisition (the 2022 Asset Acquisition) of approximately 4,600 net Marcellus acres in Northeast Pennsylvania for a total purchase price of 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.

7. NEPA Non-Operated Asset Divestitures

First NEPA Non-Operated Asset Divestiture. On May 31, 2024, the Company completed the divestiture (the First NEPA Non-Operated Asset Divestiture) of an undivided 40% interest in the Company's non-operated natural gas assets in Northeast Pennsylvania with a carrying amount of approximately $523 million to Equinor USA Onshore Properties Inc. and its affiliates (collectively, the Equinor Parties). The carrying value was composed of approximately $549 million of property, plant and equipment, approximately $6 million of other current liabilities and approximately $20 million of other liabilities and credits. In exchange, as consideration, the Company received from the Equinor Parties cash of $500 million, subject to customary post-closing purchase price adjustments, certain upstream assets and the remaining 16.25% equity interest in the NEPA Gathering System. The total fair value of consideration received, net of liabilities assumed, was approximately $832 million, subject to customary post-closing purchase price adjustments, and included $413 million of property, plant and equipment.

As a result of the First NEPA Non-Operated Asset Divestiture, the Company recognized a gain of approximately $299 million in (gain) loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations. The gain was calculated as the carrying value of the divested assets less the fair value of consideration received, net of liabilities assumed, and approximately $10 million of divestiture costs incurred. The long-lived assets divested and received and resulting gain are reported in the Company's Production segment. The Company used cash proceeds from the First NEPA Non-Operated Asset Divestiture to partly fund EQT's redemption of its 6.125% senior notes.

The fair values of the developed and undeveloped natural gas properties received as consideration for the First NEPA Non-Operated Asset Divestiture were measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. 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 operating costs and a weighted average cost of capital as well as future development plans from a market participant perspective with respect to undeveloped properties.

The fair value of the interest in the NEPA Gathering System received as consideration for the First NEPA Non-Operated Asset Divestiture was measured using the cost approach based on inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. Significant inputs include replacement cost for similar assets, relative age of the assets and potential economic or functional obsolescence.

See Note 5 for a description of the fair value hierarchy.

In addition, subsequent to the completion of the First NEPA Non-Operated Asset Divestiture, the Company and the Equinor Parties entered into a gas buy-back agreement with respect to the assets received by the Company as consideration for the First NEPA Non-Operated Asset Divestiture, whereby the Equinor Parties agreed to purchase a specified amount of natural gas from the Company through the first quarter of 2028.

Second NEPA Non-Operated Asset Divestiture. On December 31, 2024, the Company completed the divestiture (the Second NEPA Non-Operated Asset Divestiture, and, together with the First NEPA Non-Operated Asset Divestiture, the NEPA Non-Operated Asset Divestitures) of the remaining undivided 60% interest in the Company's non-operated natural gas assets in Northeast Pennsylvania with a carrying amount of approximately $772 million to the Equinor Parties. The carrying value was composed of approximately $812 million of property, plant and equipment, approximately $9 million of other current liabilities and approximately $31 million of other liabilities and credits. In exchange, as consideration, the Company received from the Equinor Parties cash of $1.25 billion, subject to customary post-closing purchase price adjustments and transaction costs.

As a result of the Second NEPA Non-Operated Asset Divestiture, the Company recognized a gain of approximately $463 million in (gain) loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations. The gain was calculated as the carrying value of the divested assets less the consideration received and approximately $7 million of divestiture costs incurred. The long-lived assets divested and resulting gain are reported in the Company's Production segment. The Company used cash proceeds from the Second NEPA Non-Operated Asset Divestiture to repay a portion of outstanding borrowings under EQT's revolving credit facility.

8. The Midstream Joint Venture Transaction

On September 24, 2024, the Company formed PipeBox LLC (the Midstream Joint Venture) as a wholly-owned subsidiary of EQM. On November 22, 2024, EQM entered into a contribution agreement (the Contribution Agreement) with an affiliate of Blackstone Credit & Insurance (the BXCI Affiliate).

On December 30, 2024, pursuant to the Contribution Agreement, EQM and certain of its affiliates contributed to the Midstream Joint Venture the following assets in exchange for 364,285,715 Class A Units in the Midstream Joint Venture: (i) EQM's ownership interest in the MVP (via EQM's Series A ownership interest in the MVP Joint Venture), (ii) EQM's regulated transmission and storage assets (including those owned by Equitrans, L.P.), and (iii) EQM's Hammerhead Pipeline System (a 1.6 Bcf per day gathering header pipeline designed to connect natural gas produced in Pennsylvania and West Virginia to the MVP, Texas Eastern Transmission and Eastern Gas Transmission). In addition, pursuant to the Contribution Agreement, on December 30, 2024, the BXCI Affiliate contributed to the Midstream Joint Venture $3.5 billion of cash, net of certain transaction fees and expenses, in exchange for a noncontrolling equity interest of 350,000,000 Class B Units in the Midstream Joint Venture (such contributions by EQM and the BXCI Affiliate, collectively, the Midstream Joint Venture Transaction).

The Midstream Joint Venture Transaction was accounted for as a sale of interest in a subsidiary without a loss of control. The Company recorded a $3.5 billion increase in noncontrolling interest in consolidated subsidiaries and a $77.5 million decrease to common shareholders' equity, inclusive of transaction-related expenses incurred by the Company and a $13.3 million deferred tax asset.

In addition, on December 30, 2024, EQT (solely for the limited purposes set forth therein), EQM, the BXCI Affiliate and the Midstream Joint Venture entered into an amended and restated limited liability company agreement of the Midstream Joint Venture (the JV Agreement). The JV Agreement provides for, among other things, quarterly distributions of available cash flow to the Midstream Joint Venture's unitholders, of which EQM, as Class A Unitholder, will receive 40% and the BXCI Affiliate, as Class B Unitholder, will receive 60% until the Base Return (as defined in the JV Agreement) has been achieved. After the Base Return has been achieved and until the 8th anniversary of the closing of the Midstream Joint Venture Transaction of December 30, 2024, 100% of the Midstream Joint Venture's distributions, including in a liquidation or sale of the Midstream Joint Venture, will be distributed to EQM as Class A Unitholder and zero percent will be distributed to the BXCI Affiliate as Class B Unitholder; after the Base Return has been achieved and from the 8th anniversary of December 30, 2024 and thereafter, no less than 95% of the Midstream Joint Venture's distributions, including in a liquidation or sale of the Midstream Joint Venture, will be distributed to EQM as Class A Unitholder, and up to 5% of the Midstream Joint Venture's distributions will be distributed to the BXCI Affiliate as Class B Unitholder (with specific distribution percentages determined based on the BXCI Affiliate's ownership of Class B Units as of the time of such distribution).

Based on the governing provisions of the JV Agreement, EQT's management determined that the allocation of income between the Company and the BXCI Affiliate should be based on the change in the investors claim on the Midstream Joint Venture's book value. Under this method, the Company recognizes net income/loss attributable to the noncontrolling interest based on changes to the amount that each member would hypothetically receive at each balance sheet date under the JV Agreement's liquidation provisions, assuming that the net assets of the Midstream Joint Venture were liquidated at the recorded amounts, after taking into account any capital transactions between the Company and the BXCI Affiliate.

The Company used the proceeds from the Midstream Joint Venture Transaction to repay outstanding borrowings, and interest thereon, under the Bridge Credit Facility (defined in Note 10) and the Term Loan Facility and a portion of outstanding borrowings under EQT's revolving credit facility as well as to pay certain transaction fees and expenses related to the Midstream Joint Venture Transaction and other related transactions. See Note 10.

9. Income Taxes

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

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Current:			
Federal	$ 1,222	$ (10,894)	$ 651
State	6,125	(4,818)	18,457
Subtotal	7,347	(15,712)	19,108
Deferred:			
Federal	(21,463)	450,091	527,539
State	36,195	(65,425)	7,073
Subtotal	14,732	384,666	534,612
Total income tax expense	$ 22,079	$ 368,954	$ 553,720

For the year ended December 31, 2024, current income tax expense is composed of state and federal income tax liabilities. For the year ended December 31, 2023, current income tax benefit related primarily to 2014 through 2017 audit settlement interest and reduction in prior year state income tax liabilities. For the year ended December 31, 2022, current income tax expense related primarily to state income tax liabilities.

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 differences from amounts computed at the federal statutory rate of 21% on pre-tax income.

	Years Ended December 31,					
	2024		2023		2022	
	Amount	Rate	Amount	Rate	Amount	Rate
	(Thousands)		(Thousands)		(Thousands)	
Income before income taxes	$ 264,194		$ 2,103,498		$ 2,334,662	
Tax at statutory rate	$ 55,481	21.0%	$ 441,735	21.0%	$ 490,279	21.0%
State income taxes	5,440	2.1%	50,263	2.4%	48,970	2.1%
Valuation allowance	(9,601)	(3.6)%	(81,483)	(3.9)%	12,685	0.5%
Convertible Notes repurchase premium	—	—%	—	—%	35,957	1.5%
Uncertain tax positions	(16,977)	(6.4)%	(7,015)	(0.3)%	11,135	0.5%
State law change	(11,315)	(4.3)%	(21,670)	(1.0)%	(49,511)	(2.1)%
Federal and state tax credits	(6,537)	(2.5)%	(4,715)	(0.2)%	(4,319)	(0.2)%
Transaction costs	6,041	2.3%	—	—%	—	—%
Other	(453)	(0.2)%	(8,161)	(0.4)%	8,524	0.4%
Income tax expense	$ 22,079	8.4%	$ 368,954	17.5%	$ 553,720	23.7%

The Company's effective tax rate for the year ended December 31, 2024 was lower compared to the U.S. federal statutory rate due primarily to the release of valuation allowances related to capital loss carryforward utilization, expiration of a statute of limitations related to uncertain tax positions, inclusive of interest, 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). The Pennsylvania Tax Legislation lowered the corporate net income tax rate from 8.99% to 8.49% in 2024 and continues to lower the corporate net income tax rate by 0.5% annually thereafter until the corporate net income tax rate reaches 4.99% in 2031. The rate reductions were partly offset by valuation allowances limiting certain state income tax benefits and non-deductible transaction costs incurred with the Equitrans Midstream Merger.

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 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.

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 income taxes, including valuation allowances limiting certain state income tax benefits and nondeductible repurchase premiums on the Convertible Notes (defined in Note 10), partly offset by state income 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 following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities.

	December 31,	
	2024	2023
	(Thousands)	
Deferred tax assets:		
NOL carryforwards	$ 708,518	$ 740,802
Interest disallowance limitation	106,622	59,668
Federal tax credits	89,644	92,730
Net unrealized losses	80,723	—
State capital loss carryforward	44,496	99,632
Incentive compensation and deferred compensation plans	18,032	16,854
Other	2,433	1,156
Deferred tax assets	1,050,468	1,010,842
Valuation allowance	(257,218)	(290,812)
Net deferred tax asset	793,250	720,030
Deferred tax liabilities:		
Property, plant and equipment	(2,516,074)	(2,457,946)
Investment in partnerships	(1,128,279)	—
Net unrealized gains	—	(166,905)
Deferred tax liability	(3,644,353)	(2,624,851)
Net deferred tax liability	$ (2,851,103)	$ (1,904,821)

During 2024, the net deferred tax liability increased by $946.3 million compared to 2023 due primarily to the additional deferred tax liability related to the Company's investment in EQM (treated as a partnership for tax purposes) and the additional deferred tax liabilities that arose from the fair value accounting of net assets acquired in the Equitrans Midstream Merger, partly offset by an increase in net unrealized losses.

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

	December 31,	
	2024	2023
	(Thousands)	
NOL carryforwards:		
Federal (expires between 2032 and 2037)	$ 14,644	$ 67,958
Federal (indefinite expiration)	322,258	323,598
State (expires between 2025 and 2037)	347,279	332,153
State (indefinite expiration)	24,337	17,093
Total NOL carryforwards	$ 708,518	$ 740,802
Valuation allowance on NOL carryforwards:		
Federal	$ (14,263)	$ (24,927)
State	(187,321)	(156,700)
Total valuation allowance on NOL carryforwards	$ (201,584)	$ (181,627)

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 2024 and 2023, 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 and 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 state capital loss carryforwards were warranted as it was more likely than not that the Company would not use them prior to expiration.

The remaining valuation allowance (which is not included in the NOL table above) is related primarily to the state capital loss carryforward realized with the sales of the Company's equity investment in Equitrans Midstream occurring between February 2020 and April 2022, 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 April 2022, the Company sold the remaining portion of its equity investment in Equitrans Midstream, which generated a capital loss that can only be carried forward for potential future utilization. During 2024, the Company recognized capital gains from the NEPA Non-operated Asset Divestitures that allowed the Company to recognize in the Statement of Consolidated Operations a federal and state income tax benefit of $52.8 million and $2.3 million, respectively, related to its valuation allowances for its capital loss carryforwards.

As of December 31, 2024, the Company had a valuation allowance related to the capital loss carryforward of $44.5 million for state income tax purposes due to the limitations on future potential utilization. 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 purposes and $46.8 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.

	2024	2023	2022
		(Thousands)	
Balance at January 1	$ 89,197	$ 204,035	$ 182,032
Additions for tax positions taken in current year	11,720	11,986	9,612
Additions (reductions) for tax positions taken in prior years	15,177	(883)	12,391
Reductions for tax positions settled with tax authorities	(29,645)	(125,941)	—
Reductions for lapse in statute of limitations	(13,706)	—	—
Balance at December 31	$ 72,743	$ 89,197	$ 204,035

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

	December 31,		
	2024	2023	2022
		(Thousands)	
If recognized, effect to the effective tax rate	$ 67,105	$ 83,669	$ 117,341
Reduction of related deferred tax asset for general business credit carryforwards and NOLs	$ 60,415	$ 77,013	$ 110,744

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded interest and penalties expense (income) of approximately $0.6 million, $(19.8) million and $6.7 million for the years ended December 31, 2024, 2023 and 2022, respectively. Interest and penalties of $2.9 million, $2.3 million, and $22.2 million were included in the Consolidated Balance Sheets as of December 31, 2024, 2023 and 2022, respectively.

As of December 31, 2024, the Company believed that, as a result of potential settlements with relevant taxing authorities, it is reasonably possible that a decrease of $14.6 million in unrecognized tax benefits related to state income tax positions may be necessary within twelve months.

In September 2024, the Company settled its consolidated U.S. federal income tax liability with the IRS through 2019 for amounts included in the reserve for uncertain tax positions with minimal impact to the effective tax rate. The settlement resulted in forgone research and development tax credits of $29.6 million, which are reflected in the table above. The refundable alternative minimum tax credits realized with the settlement of the previous IRS audit are included in the income tax receivable in the Consolidated Balance Sheet as of December 31, 2024. As of December 31, 2024, the Company is no longer subject to state examinations by income tax authorities for years prior to 2016 and has considered ongoing state income tax matters in its reserve for uncertain tax positions.

There were no material changes to the Company's methodology for accounting for unrecognized tax benefits during 2024.

10. Debt

The table below summarizes the Company's outstanding debt.

	December 31, 2024			December 31, 2023		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
			(Thousands)			
EQT's revolving credit facility maturing July 23, 2029	$ 150,000	$ 150,000	$ 150,000	$ —	$ —	$ —
Eureka's revolving credit facility maturing November 13, 2025	320,800	320,800	320,800	—	—	—
Term Loan Facility due June 30, 2026	—	—	—	1,250,000	1,244,265	1,244,265
Debentures and senior notes:						
EQT's 6.125% notes due February 1, 2025 (c)	—	—	—	601,521	600,389	605,082
EQT's 1.75% convertible notes due May 1, 2026	—	—	—	290,177	286,185	768,554
EQT's 3.125% notes due May 15, 2026	392,915	391,193	382,994	392,915	389,978	373,261
EQT's 7.75% debentures due July 15, 2026	115,000	114,213	119,590	115,000	113,716	121,590
EQM's 7.500% notes due June 1, 2027	500,000	511,377	510,140	—	—	—
EQM's 6.500% notes due July 1, 2027	900,000	915,538	912,159	—	—	—
EQT's 3.90% notes due October 1, 2027	1,169,503	1,166,523	1,137,248	1,169,503	1,165,439	1,121,027
EQT's 5.700% notes due April 1, 2028	500,000	492,640	508,695	500,000	490,376	509,280
EQM's 5.500% notes due July 15, 2028	118,683	118,204	117,382	—	—	—
EQT's 5.00% notes due January 15, 2029	318,494	315,785	314,357	318,494	315,121	316,784
EQM's 4.50% notes due January 15, 2029	742,923	711,754	711,297	—	—	—
EQM's 6.375% notes due April 1, 2029	600,000	608,667	606,774	—	—	—
EQT's 7.000% notes due February 1, 2030 (c)	674,800	671,641	718,358	674,800	671,020	726,645
EQM's 7.500% notes due June 1, 2030	500,000	535,671	534,950	—	—	—
EQM's 4.75% notes due January 15, 2031	1,100,000	1,045,219	1,039,995	—	—	—
EQT's 3.625% notes due May 15, 2031	435,165	430,818	388,111	435,165	430,141	389,925
EQT's 5.750% notes due February 1, 2034	750,000	742,796	744,743	—	—	—
EQM's 6.500% notes due July 15, 2048	80,233	81,338	81,932	—	—	—
EQT's note payable to EQM	—	—	—	88,483	88,483	91,063
Total debt	9,368,516	9,324,177	9,299,525	5,836,058	5,795,113	6,267,476
Less: Current portion of debt (d)	320,800	320,800	320,800	296,424	292,432	774,983
Long-term debt	$9,047,716	$9,003,377	$8,978,725	$5,539,634	$5,502,681	$5,492,493

(a) For EQT's revolving credit facility, Eureka's revolving credit facility and, as of December 31, 2023, EQT's note payable to EQM, the principal value represents carrying value. For all other debt, the principal value less the unamortized debt issuance costs and debt discounts and, for EQM's senior notes, the unamortized fair value adjustments recorded with Equitrans Midstream Merger purchase price accounting represents carrying value.

(b) The carrying value of borrowings under EQT's revolving credit facility, Eureka's revolving credit facility and, as of December 31, 2023, the Term Loan Facility approximates fair value as their interest rates are based on prevailing market rates; therefore, the Company considers the fair value of EQT's revolving credit facility, Eureka's revolving credit facility and the Term Loan Facility to be Level 1 fair value measurements. As of December 31, 2023, the Company measured the fair value of EQT's note payable to EQM using Level 3 inputs. For all other debt, fair value is measured using Level 2 inputs. See Note 5 for the fair value hierarchy.

(c) Interest rates for EQT's 7.000% senior notes fluctuate based on changes to the credit ratings assigned to EQT's senior notes by Moody's, S&P and Fitch. Prior to their redemption, interest rates for EQT's 6.125% senior notes fluctuated based on changes to the credit ratings assigned to EQT's senior notes by Moody's, S&P and Fitch. Interest rates for the Company's other senior notes do not fluctuate.

(d) As of December 31, 2024, the current portion of debt included borrowings outstanding under Eureka's revolving credit facility. As of December 31, 2023, the current portion of debt included EQT's 1.75% convertible notes and a portion of EQT's note payable to EQM. Upon the closing of the Equitrans Midstream Merger, EQT's note payable to EQM became an intercompany transaction on a consolidated basis and, as such, was effectively settled on July 22, 2024.

Debt Repayments. The Company repaid, redeemed or repurchased the following debt during the year ended December 31, 2024.

Debt Tranche	**Principal**	**Premiums/ (Discounts)**	**Accrued but Unpaid Interest**	**Total Cost**
		(Thousands)		
EQM's 6.000% notes due July 1, 2025 (a)	$ 400,000	$ 1,284	$ 11,933	$ 413,217
EQM's 4.125% notes due December 1, 2026 (a)	500,000	—	1,662	501,662
EQM's 5.500% notes due July 15, 2028 (a)	731,317	15,541	18,435	765,293
EQM's 4.50% notes due January 15, 2029 (a)	57,077	(713)	1,177	57,541
EQM's 6.500% notes due July 15, 2048 (a)	469,767	27,012	13,995	510,774
EQM's 4.00% notes due August 1, 2024	300,000	—	6,000	306,000
EQT's 6.125% notes due February 1, 2025	601,521	1,178	13,612	616,311
Term Loan Facility due June 30, 2026	1,250,000	15	6,136	1,256,151
EQT's 1.75% convertible notes due May 1, 2026	583	—	—	583
Total	$ 4,310,265	$ 44,317	$ 72,950	$ 4,427,532

(a) In addition to call premiums (discounts) disclosed, EQM paid $7.8 million in third-party advisory costs and fees to dealer managers and brokers for the redemption of its 6.000% senior notes, redemption of its 4.125% senior notes and repayment of certain of its senior notes in the EQM Tender Offer (defined below).

EQT's Revolving Credit Facility. EQT has a $3.5 billion revolving credit facility. On July 22, 2024, EQT entered into a Fourth Amended and Restated Credit Agreement (as amended from time to time, the EQT Credit Agreement) with PNC Bank National Association, as administrative agent, swing line lender and L/C issuer, and the other lenders party thereto, amending and restating the Third Amended and Restated Credit Agreement, dated June 28, 2022 (the Third A&R Credit Agreement), under which such lenders agreed to make to EQT unsecured revolving loans in an aggregate principal amount of up to $3.5 billion. The EQT Credit Agreement, among other things, (i) extended the maturity date of the commitments and loans under the Third A&R Credit Agreement to July 23, 2029 and provides, at EQT's option, two one-year extensions thereafter, subject to satisfaction of certain conditions, and (ii) allows for additional commitment increases up to $1 billion, subject to the agreement of EQT and new or existing lenders. EQT can obtain Base Rate Loans (as defined in the EQT Credit Agreement) or Term SOFR Rate Loans (as defined in the EQT Credit Agreement). Base Rate Loans are denominated in dollars and bear interest at a Base Rate (as defined in the EQT Credit Agreement) plus a margin ranging from 12.5 basis points to 100 basis points determined on the basis of EQT's credit ratings. Term SOFR Rate Loans bear interest at a Term SOFR Rate (as defined in the EQT Credit Agreement) plus an additional 10 basis point credit spread adjustment plus a margin ranging from 112.5 basis points to 200 basis points determined on the basis of EQT's credit ratings.

EQT's revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. EQT'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 EQT. As of December 31, 2024, no one lender of the large group of financial institutions in the syndicate for EQT'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.

EQT is not required to maintain compensating bank balances. EQT'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 EQT's revolving credit facility in addition to the interest rate charged by the lenders on any amounts borrowed against EQT's revolving credit facility; the lower EQT's debt credit rating, the higher the level of fees and borrowing rate.

EQT's revolving credit facility contains various provisions that, if not complied with, could result in termination of EQT's revolving credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under EQT's revolving credit facility are the maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. EQT'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, 2024, EQT was in compliance with all provisions and covenants of the EQT Credit Agreement.

As of December 31, 2024 and 2023, the Company had approximately $1 million and $15 million, respectively, of letters of credit outstanding under EQT's revolving credit facility.

For the years ended December 31, 2024, 2023 and 2022, under EQT's revolving credit facility, the maximum amount of outstanding borrowings was $2,357 million, $269 million and $1,300 million, respectively, the average daily balance was approximately $936 million, $40 million and $466 million, respectively, and interest was incurred at a weighted average annual interest rate of 6.6%, 6.9% and 2.8%, respectively. For all years ended December 31, 2024, 2023 and 2022, the Company incurred commitment fees of approximately 20 basis points on the undrawn portion of EQT's revolving credit facility to maintain credit availability.

Eureka's Revolving Credit Facility. Upon the closing of the Equitrans Midstream Merger, the Company acquired a controlling interest in Eureka Midstream Holdings. See Notes 1 and 6. Eureka, a wholly-owned subsidiary of Eureka Midstream Holdings, has a $400 million senior secured revolving credit facility pursuant to that certain Credit Agreement, dated May 13, 2021, among Eureka, Sumitomo Mitsui Banking Corporation, as administrative agent, the lenders party thereto from time to time and any other persons party thereto from time to time (as amended from time to time, the Eureka Credit Agreement). Eureka can obtain Base Rate Loans (as defined in the Eureka Credit Agreement) or Term SOFR Rate Loans (as defined in the Eureka Credit Agreement), each plus a margin based on Eureka's consolidated leverage ratio. Base Rate Loans are denominated in dollars and bear interest at a Base Rate (as defined in the Eureka Credit Agreement) plus a margin ranging from 100 basis points to 225 basis points determined on the basis of Eureka's consolidated leverage ratio. Term SOFR Rate Loans bear interest at a Term SOFR Rate (as defined in the Eureka Credit Agreement) plus an additional 10 basis point credit spread adjustment plus a margin ranging from 200 basis points to 325 basis points determined on the basis of Eureka's consolidated leverage ratio.

Eureka's revolving credit facility contains negative covenants that, among other things, limit restricted payments, incurrence of debt, dispositions, mergers and other fundamental changes and transactions with affiliates, in each case and as applicable, subject to certain specified exceptions. In addition, Eureka's revolving credit facility contains certain specified events of default, including insolvency, nonpayment of scheduled principal or interest obligations, loss and failure to replace certain material contracts, change of control and cross-default provisions related to the acceleration or default of certain other financial obligations. As of December 31, 2024, Eureka was in compliance with all provisions and covenants of the Eureka Credit Agreement.

As of December 31, 2024, Eureka had no letters of credit outstanding under its revolving credit facility.

For the period beginning on July 22, 2024 and ending on December 31, 2024, under Eureka's revolving credit facility, the maximum amount of outstanding borrowings was $330 million, the average daily balance was $328 million and interest was incurred at a weighted average annual interest rate of 7.8%. For the period beginning on July 22, 2024 and ending on December 31, 2024, the Company incurred commitment fees of approximately 50 basis points on the undrawn portion of Eureka's revolving credit facility to maintain credit availability.

EQM's Bridge Credit Facility. In connection with its entry into the Contribution Agreement, on November 22, 2024, EQM entered into a debt commitment letter with Royal Bank of Canada (EQM Debt Commitment Letter), pursuant to which Royal Bank of Canada committed, subject to satisfaction of certain conditions, to provide EQM with a senior unsecured bridge term loan facility in an aggregate principal amount of up to $2.3 billion (the Bridge Credit Facility). On December 27, 2024, EQM entered into the Bridge Credit Facility and borrowed $2.23 billion thereunder to fund (with cash on hand) the redemption and repurchase of certain of EQM's senior notes. See "Debt Repayments" table and "EQM's Senior Notes." Upon the closing of the Midstream Joint Venture discussed in Note 8, the Company used a portion of the proceeds from the Midstream Joint Venture Transaction to repay outstanding borrowings, and interest thereon, under the Bridge Credit Facility, and, thereafter, EQM terminated the Bridge Credit Facility.

EQM's Revolving Credit Facility. Immediately following the closing of the Equitrans Midstream Merger, on July 22, 2024, EQM repaid outstanding obligations under that certain Third Amended and Restated Credit Agreement, dated October 31, 2018, by and among EQM, Wells Fargo Bank, National Association, as administrative agent, swing line lender and L/C issuer, and the other financial institutions from time to time party thereto for principal of $705 million and interest and fees of $4.5 million using cash on hand and cash contributions from EQT funded by borrowings under EQT's revolving credit facility, and, thereafter, EQM terminated its revolving credit facility.

Term Loan Facility. On November 9, 2022, EQT entered into a Credit Agreement (as amended from time to time, 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 EQT 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, EQT borrowed $1.25 billion under the Term Loan Facility, receiving net proceeds 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.

On January 16, 2024, EQT 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 EQT's prepayment of $750 million principal amount of the term loans outstanding under the Term Loan Facility (funded with the net proceeds from the issuance of EQT's 5.750% senior notes and cash on hand) and the satisfaction of other closing conditions. On July 22, 2024, EQT entered into a fourth amendment to the Term Loan Agreement to, among other things, make certain conforming changes to the Term Loan Agreement in alignment with the EQT Credit Agreement.

Upon the closing of the Midstream Joint Venture, the Company used a portion of the proceeds from the Midstream Joint Venture Transaction to repay the remaining $500 million of outstanding borrowings, and interest thereon, under the Term Loan Facility, and, thereafter, EQT terminated the Term Loan Facility. Refer to "Debt Repayments" for details.

Prior to their prepayment, the term loans outstanding under the Term Loan Facility bore interest at either (at EQT's election) a Term SOFR Rate plus the SOFR Adjustment or Base Rate (both terms defined in the Term Loan Agreement), each plus a margin based on EQT's credit ratings. For the period beginning on January 1, 2024 and ending on December 30, 2024, interest under the Term Loan Facility was incurred at a weighted average annual interest rate of 6.8%. For the period beginning on August 21, 2023 and ending on December 31, 2023, interest under the Term Loan Facility was incurred at a weighted average annual interest rate of 6.9%.

EQM's Senior Notes. Upon the closing of the Equitrans Midstream Merger, EQM became an indirect wholly-owned subsidiary of EQT, and EQM's outstanding senior notes were consolidated by the Company.

The indentures governing EQM's senior notes contain certain restrictive financial and operating covenants, including covenants that restrict, among other things, EQM'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 EQM'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.

On November 25, 2024, the Company announced EQM's commencement of a tender offer (the EQM Tender Offer) to purchase certain of EQM's senior notes, subject to a maximum aggregate purchase price, excluding accrued and unpaid interest, of up to $1.275 billion, in accordance with acceptance priority levels correlating to the order in which the notes are listed as follows: EQM's 6.500% senior notes due 2048, EQM's 5.500% senior notes due 2028, EQM's 4.50% senior notes due 2029 and EQM's 7.500% senior notes due 2030. On December 10, 2024, the Company announced the early results of the EQM Tender Offer, including an increase of the maximum aggregate purchase price to $1.3 billion. On December 27, 2024, EQM used borrowings under the Bridge Credit Facility and cash on hand to fund the EQM Tender Offer. Refer to "Debt Repayments" for details. In accordance with the established acceptance priority levels, none of EQM's 7.500% senior notes due 2030 were purchased.

In conjunction with the EQM Tender Offer, EQM solicited consents from holders of its 6.500% senior notes due 2048 and 5.500% senior notes due 2028 (such notes, together, the Affected Notes) to amend that certain Indenture, dated as of August 1, 2014, solely with respect to the Affected Notes, by modifying the reporting covenant contained therein such that EQT would provide the financial statements and other information required thereby in lieu of EQM (the Proposed Amendment). Each holder who validly tendered Affected Notes pursuant to the EQM Tender Offer was deemed to have validly delivered its related consent to the Proposed Amendment, and, therefore, EQM received the requisite consents to effect the Proposed Amendment. On December 30, 2024, EQM and The Bank of New York Mellon Trust Company, N.A., as trustee for the Affected Notes, entered into that certain Sixth Supplemental Indenture containing the Proposed Amendment, which immediately became effective and operative upon such entry and applies to all holders of Affected Notes that remain outstanding.

On December 30, 2024, EQM used borrowings under the Bridge Credit Facility and cash on hand to redeem its 6.000% senior notes due 2025 and 4.125% senior notes due 2026. Refer to "Debt Repayments" for details.

As of December 31, 2024, aggregate maturities for EQM's senior notes were zero in 2025 and 2026, $1,400 million in 2027, $119 million in 2028, $1,343 million in 2029 and $1,680 million thereafter.

EQT's Senior Notes. The indentures governing EQT's long-term indebtedness contain certain restrictive financial and operating covenants, including covenants that restrict, among other things, EQT'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 EQT'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.

On January 19, 2024, EQT issued $750 million aggregate principal amount of 5.750% senior notes due 2034. The Company used net proceeds of $742.0 million from the sale and issuance of such notes and cash on hand to prepay $750 million principal amount of the term loans outstanding under the Term Loan Facility.

As of December 31, 2024, aggregate maturities for EQT's senior notes were zero in 2025, $508 million in 2026, $1,170 million in 2027, $500 million in 2028, $318 million in 2029 and $1,860 million thereafter.

EQT's 1.75% Convertible Notes. In April 2020, EQT issued $500 million aggregate principal amount of 1.75% convertible senior notes (the Convertible Notes). The effective interest rate for the Convertible Notes was 2.4%.

On January 2, 2024, in accordance with the indenture governing the Convertible Notes (the Convertible Notes Indenture), EQT issued an irrevocable notice of redemption for all of the outstanding Convertible Notes and announced that EQT 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, between January 2, 2024 and the conversion deadline of 5:00 p.m., New York City time, on January 12, 2024, certain holders of the Convertible Notes exercised their right to convert their Convertible Notes prior to the redemption and validly surrendered an aggregate principal amount of $289.6 million of Convertible Notes. Based on a conversion rate of 69.0364 shares of EQT common stock per $1,000 principal amount of Convertible Notes, EQT issued to such holders an aggregate 19,992,482 shares of EQT common stock. Settlement of such Convertible Note conversion right exercises net of unamortized deferred issuance costs increased shareholder's equity by $285.6 million. The remaining $0.6 million in outstanding principal amount of Convertible Notes was redeemed on January 17, 2024 in cash for the Redemption Price.

Inclusive of January 2024 settlements of Convertible Notes conversion right exercises that were exercised in December 2023, during January 2024, EQT settled $290.2 million aggregate principal amount of Convertible Notes conversion right exercises by issuing an aggregate 20,036,639 shares of EQT common stock to the converting holders at an average conversion price of $38.03.

Settlement and Termination of Capped Call Transactions. In connection with, but separate from, the issuance of the Convertible Notes, in 2020, EQT entered into capped call transactions (the Capped Call Transactions) with certain financial institutions (the Capped Call Counterparties) to reduce the potential dilution to EQT 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 common stock and an initial cap price of $18.75 per share of EQT common stock, each of which were subject to certain customary adjustments, including adjustments as a result of EQT 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, EQT entered into separate termination agreements with each of the Capped Call Counterparties, pursuant to which the Capped Call Counterparties paid EQT an aggregate $93.3 million (the Termination Payments), and the Capped Call Transactions were terminated. EQT received the Termination Payments on January 22, 2024. The Termination Payments were recorded as an increase to shareholders' equity.

11. Investments in Unconsolidated Entities

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'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.

The table below summarizes the Company's equity method investments.

	December 31, 2024		December 31, 2023	
	Ownership Interest	Carrying Value	Ownership Interest	Carrying Value
		(Thousands)		(Thousands)
MVP Joint Venture (a):				
The MVP (b)	49.3 %	$ 3,469,438	— %	$ —
MVP Southgate	47.2 %	65,292	— %	—
Total MVP Joint Venture		3,534,730		—
Laurel Mountain Midstream, LLC (c)	31 %	28,757	31 %	39,923
WATT Fuel Cell Corporation (d)	15.63 %	14,533	15.43 %	16,700
Yellowbird Energy LLC (e)	50 %	6,135	— %	—
Total		$ 3,584,155		$ 56,623

(a) Mountain Valley Pipeline, LLC (the MVP Joint Venture) is a Delaware series limited liability company joint venture formed among (i) with respect to Series A, an affiliate of EQT and affiliates of each of NextEra Energy, Inc., Consolidated Edison, Inc., AltaGas Ltd. and RGC Resources, Inc. for purposes of constructing, owning and operating the MVP and (ii) with respect to Series B, a wholly-owned subsidiary of EQT and affiliates of NextEra Energy, Inc., AltaGas Ltd. and RGC Resources, Inc. for purposes of constructing, owning and operating MVP Southgate.
(b) As discussed in Note 8, upon the completion of the Midstream Joint Venture Transaction, the Company contributed its interest in the MVP (via its Series A ownership interest in the MVP Joint Venture) to the Midstream Joint Venture.
(c) Laurel Mountain Midstream, LLC is a natural gas gathering and processing joint venture formed among the Company, Williams Companies Inc. and certain other energy companies.
(d) Watt Fuel Cell Corporation is a developer and manufacturer of solid oxide fuel cell systems that operate on common, readily available fuels such as natural gas and propane.
(e) Yellowbird Energy LLC is a joint venture formed in 2024 between a subsidiary of EQT and a third-party investor.

The MVP. The MVP is a 303-mile long, 42-inch diameter natural gas interstate pipeline with a total capacity of 2.0 Bcf per day that spans from the Company's transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia. Following receipt of authorization from the Federal Energy Regulatory Commission (the FERC), the MVP entered into service on June 14, 2024 and became available for interruptible or short-term firm transportation service. On July 1, 2024, the MVP commenced long-term firm capacity obligations. A wholly-owned subsidiary of EQM is the operator of the MVP.

Estimated total project cost of the MVP is approximately $8.1 billion, including contingency and excluding AFUDC during construction. Of this amount, $142.8 million was contributed by the Company following the completion of the Equitrans Midstream Merger.

The Company has a negative basis difference between the carrying value of its equity method investment in the MVP and its proportionate share of the MVP's net assets (composed of fixed assets). The basis difference is accreted over the useful life of the fixed assets, with accretion expense presented in (income) loss from investments in the Company's Statement of Consolidated Operations. As of December 31, 2024, the basis difference, net of accretion, was $1.3 billion.

For the year ended December 31, 2024, the Company's Series A ownership interest (with respect to the MVP) in the MVP Joint Venture was significant as defined by the SEC's Regulation S-X Rule 1-02(w). Accordingly, pursuant to Regulation S-X Rule 4-08(g), the following table presents summarized financial information of the MVP Joint Venture in relation to the MVP for the period beginning on July 22, 2024 and ending December 31, 2024 and as of December 31, 2024.

	July 22, 2024 to December 31, 2024
	(Thousands)
Operating revenues	$ 247,360
Operating income	$ 126,202
Net income	$ 129,773

	December 31, 2024
	(Thousands)
Current assets	$ 204,028
Noncurrent assets	9,535,975
Total assets	$ 9,740,003
Current liabilities	$ 69,303
Noncurrent liabilities	1,514
Total liabilities	70,817
Members' equity	9,669,186
Total liabilities and members' equity	$ 9,740,003

MVP Southgate. MVP Southgate is a contemplated interstate pipeline that was approved by the FERC. The pipeline was initially designed to extend approximately 75 miles from the MVP in Pittsylvania County, Virginia to new delivery points in Rockingham and Alamance Counties, North Carolina using 24-inch and 16-inch diameter pipe.

In December 2023, the MVP Joint Venture entered into precedent agreements with Public Service Company of North Carolina, Inc. and Duke Energy Carolinas, LLC. The precedent agreements contemplate a modified project and, among other things, describe certain conditions precedent to the parties' respective obligations regarding MVP Southgate. As modified, the natural gas interstate pipeline would extend approximately 31 miles from the terminus of the MVP in Pittsylvania County, Virginia to planned new delivery points in Rockingham County, North Carolina using 30-inch diameter pipe and have a targeted capacity of 550,000 dekatherms per day. The proposed 31-mile route passes through a portion of the Southern Virginia Mega Site at Berry Hill, which is one of the largest business parks on the East Coast.

On February 3, 2025, the MVP Joint Venture filed an application with the FERC seeking to amend its existing Certificate of Public Convenience and Necessity to reflect the amended project. The Company expects a wholly-owned subsidiary of EQM to operate MVP Southgate upon its completion, which is targeted for June 2028. MVP Southgate is estimated to have a total cost of approximately $370 million to $430 million, excluding AFUDC and certain costs incurred for purposes of the originally certificated project, of which the Company will fund its proportionate share through capital contributions to the MVP Joint Venture.

Pursuant to the MVP Joint Venture's limited liability company agreement and upon the closing of the Equitrans Midstream Merger, the Company is obligated to provide performance assurances with respect to MVP Southgate that may take the form of a guarantee from EQM (provided that, in accordance with the requirements of the MVP Joint Venture's limited liability company agreement, EQM's debt is assigned an investment grade credit rating), a letter of credit or cash collateral. Upon receipt of the FERC's initial release to begin construction of MVP Southgate, the Company will be obligated to provide performance assurance in an amount equal to 33% of its share of MVP Southgate's remaining capital commitments under the applicable construction budget.

Investments in Equity Securities

The Company accounts for its investments in entities that the Company does not have the ability to exercise significant influence over as an investment in equity security. Changes in the fair value of the Company's investments in equity securities are recorded in (income) loss from investments and dividends received on the Company's investments in equity securities are recorded in other income in the Statements of Consolidated Operations.

The Investment Fund. As of December 31, 2024, 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. As of December 31, 2024 and 2023, the fair value of the Company's investment in the Investment Fund was $33.2 million and $36.1 million, respectively, and was presented in investments in unconsolidated entities 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.

Equitrans Midstream. Prior to the Company's sale of all of its then-owned shares of Equitrans Midstream common stock in 2022, the Company accounted for its investment in Equitrans Midstream as an investment in equity security.

12. Common Stock and Income Per Share

On July 18, 2024, following approval by its shareholders, EQT amended its Restated Articles of Incorporation to increase the authorized number of shares of EQT common stock from 640,000,000 shares to 1,280,000,000 shares.

As of December 31, 2024, the Company had reserved 19.3 million shares of authorized and unissued EQT common stock for stock compensation plans.

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 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 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, and, on December 18, 2024, the Company announced that its Board of Directors approved an additional two-year extension of the Share Repurchase Program. As a result of such extension, the Share Repurchase Program will expire on December 31, 2026, but it may be suspended, modified or discontinued at any time without prior notice.

From the Share Repurchase Program's inception and through December 31, 2024, the Company has purchased shares under the Share Repurchase Program for an aggregate purchase price of $622.1 million, excluding fees, commissions and expenses. The table below summarizes the Company's share repurchases under the Share Repurchase Program for the years ended December 31, 2023 and 2022. The Company did not repurchase any equity securities during the year ended December 31, 2024.

	Total number of shares purchased	Aggregate purchase price (a)	Average price paid per share (a)
		(Millions)	
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	19,045,800	$ 592.7	

(a) Excludes fees and broker commissions.

See Note 10 for a discussion of the Company's issuance of shares of EQT common stock for its settlement of Convertible Notes conversion right exercises.

In July 2024, the Company issued 152,427,848 shares of EQT common stock as part of the consideration for the Equitrans Midstream Merger described in Note 6.

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

Income Per Share. Basic income per share is computed by dividing net income 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 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 their redemption, the Convertible Notes. Purchases of treasury shares are calculated using the average share price of EQT common stock during the period. Prior to their 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,		
	2024	2023	2022
	(Thousands, except per share amounts)		
Net income attributable to EQT Corporation – Basic income available to shareholders	$ 230,577	$ 1,735,232	$ 1,770,965
Add back: Interest expense on Convertible Notes, net of tax	86	7,551	8,019
Diluted income available to shareholders	$ 230,663	$ 1,742,783	$ 1,778,984
Weighted average common stock outstanding – Basic	509,597	380,902	370,048
Options, restricted stock, performance awards and stock appreciation rights	4,625	5,232	5,731
Convertible Notes	371	27,090	30,716
Weighted average common stock outstanding – Diluted	514,593	413,224	406,495
Income per share of common stock attributable to EQT Corporation:			
Basic	$ 0.45	$ 4.56	$ 4.79
Diluted	$ 0.45	$ 4.22	$ 4.38

13. Share-Based Compensation Plans

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

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Incentive Performance Share Unit Programs	$ 20,919	$ 23,915	$ 23,443
Restricted stock awards	25,473	20,119	23,028
Stock appreciation rights	—	4,056	17,406
Other programs, including non-employee director awards	3,596	3,110	3,534
Total share-based compensation expense (a)	$ 49,988	$ 51,200	$ 67,411

(a) For the years ended December 31, 2024 and 2023, share-based compensation expense of $105.4 million and $3.6 million, respectively, was included in other operating expenses. Share-based compensation expense for 2024 related primarily to the Equitrans Midstream Merger. 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 years ended December 31, 2024 and December 31, 2022 was $5.1 million and $15.9 million, respectively. There was no cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2023. During the years ended December 31, 2024, 2023 and 2022, share-based payment arrangements paid in stock generated tax benefits of $7.7 million, $16.5 million and $4.1 million, respectively. Cash paid for taxes related to net settlement of share-based incentive awards for the years ended December 31, 2024, 2023 and 2022 were $102.9 million, $41.8 million and $24.8 million, respectively.

Incentive Performance Share Unit Programs

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):

- 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;
- 2023 Incentive Performance Share Unit Program (2023 Incentive PSU Program) under the 2020 LTIP; and
- 2024 Incentive Performance Share Unit Program (2024 Incentive PSU Program) under the 2020 LTIP.

The programs noted above are collectively referred to as the Incentive PSU Programs and all granted equity 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 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 years 2023 and 2024 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 2020 Incentive PSU Program varied between zero to 150% of the number of outstanding units contingent upon the performance metrics listed above. The 2021 Incentive PSU Program, 2023 Incentive PSU Program and 2024 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 2024 Incentive PSU Program 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 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 the grant date fair value for each possible performance condition outcome on the grant date. 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 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	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at December 31, 2021	2,754,648	$ 16.08	$ 44,281,509
Granted in Period	575,120	29.73 (a)	17,098,318
Granted from Multiplier	162,183	29.45	4,776,289
Vested	(625,563)	29.45	(18,422,830)
Forfeited	(4,398)	13.28	(58,405)
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	(70,616)	37.59	(2,654,455)
Outstanding at December 31, 2023	1,831,553	28.27	51,770,381
Granted in Period	371,500	40.08	14,889,720
Granted from Multiplier	451,805	23.55	10,640,008
Vested	(1,355,415)	23.55	(31,920,023)
Forfeited	(7,092)	45.94	(325,806)
Outstanding at December 31, 2024	1,292,351	$ 34.86	$ 45,054,280

(a) 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.

Total capitalized compensation costs related to the Incentive PSU Programs for the years ended December 31, 2024, 2023 and 2022 were $0.5 million, $0.6 million and $0.6 million, respectively. As of December 31, 2024, $10.2 million and $4.8 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2024 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,				
	2024	**2023 (a)**	**2022**	**2021 (a)**	**2020 (b)**
Risk-free rate	4.35%	4.16%	1.52%	0.18%	1.22%
Volatility factor	48.82%	59.31%	65.38%	72.50%	45.41%
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 982,990, 953,270 and 1,288,430 restricted stock unit equity awards to employees of the Company during the years ended December 31, 2024, 2023 and 2022, 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, 2024, 2023 and 2022, the weighted average fair value of these restricted stock unit grants, based on the grant date fair value of EQT common stock, was approximately $34.54, $31.88 and $21.65, respectively.

In conjunction with the Equitrans Midstream Merger, the Company assumed all outstanding and unvested share-based compensation awards of Equitrans Midstream and converted those assumed awards into 5,175,814 restricted stock unit equity awards. Employees who were terminated on the closing date were immediately vested in their Company awards. Company awards of those employees who continued employment with the Company under a transition agreement will vest upon the earlier of (i) the end of the vesting period set forth in the original award agreement or (ii) the end of such employee's employment period set forth in their transition agreement, in both cases subject to continued service through such date. Company awards of those employees who continued employment with the Company on an at will basis will vest in accordance with the vesting period set forth in the original award agreement, assuming continued service through such date. The fair value of these converted restricted stock awards was approximately $106.3 million of post-combination expense as of December 31, 2024.

The total fair value of restricted stock unit equity awards vested during the years ended December 31, 2024, 2023 and 2022 was $155.5 million, $23.5 million and $16.6 million, respectively. Total capitalized compensation costs related to the restricted stock unit equity awards was $9.6 million, $5.7 million and $6.6 million for the years ended December 31, 2024, 2023 and 2022, respectively.

As of December 31, 2024, $44.1 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 1.0 year.

The following table summarizes restricted stock unit equity award activity as of December 31, 2024.

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
Granted	982,990	34.54	33,950,507
Vested	(4,861,796)	31.98	(155,480,899)
Conversion of Equitrans Midstream awards	5,175,814	35.88	185,708,206
Forfeited	(90,641)	31.92	(2,893,279)
Outstanding at December 31, 2024	3,424,169	$ 33.32	$ 114,104,385

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 common stock at the time of grant. Expected volatilities are based on historical volatility of EQT 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 2024, 2023 and 2022.

	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, 2024, 2023 and 2022 was $0.7 million, $1.4 million and $20.2 million, respectively.

The following table summarizes option activity as of December 31, 2024.

Non-Qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2024	1,523,536	$ 18.75		
Expired	(193,726)	46.21		
Exercised	(134,474)	37.91		
Outstanding and Exercisable at December 31, 2024	1,195,336	$ 12.14	2.3 years	$ 40,604,986

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 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 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.

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 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 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 564,968 non-employee director share-based awards, including accrued dividends, were outstanding as of December 31, 2024. A total of 70,930, 66,300 and 44,800 share-based awards were granted to non-employee directors during the years ended December 31, 2024, 2023 and 2022, respectively. The weighted average fair value of these grants, based on the closing price of EQT common stock on the business day prior to the grant date, was $36.14, $33.31 and $43.97 for the years ended December 31, 2024, 2023 and 2022, respectively.

2025 Awards

Effective in 2025, the Compensation Committee adopted the 2025 Incentive Performance Share Unit Program (2025 Incentive PSU Program) under the 2020 LTIP. The 2025 Incentive PSU Program was established to align the interests of executives and key employees with the interests of shareholders and the strategic objectives of the Company. A total of 374,800 share units were granted under the 2025 Incentive PSU Program. The payout of the share units will vary between zero and 200% of the number of outstanding units contingent upon the Company's absolute total shareholder return and total shareholder return relative to a predefined peer group over the period of January 1, 2025 through December 31, 2027.

Effective in 2025, the Compensation Committee granted 1,111,480 restricted stock unit equity awards that follow a three-year graded vesting schedule commencing with the date of grant, assuming continued employment through each vesting date. The share total includes the Company's "equity-for-all" program, instituted in 2021, pursuant to which the Company grants equity awards to all permanent employees.

14. Leases

The Company leases drilling rigs, facilities (including a water storage facility), 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, 2024 and 2023, the Company was not a lessor.

The following table summarizes the Company's lease costs.

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Operating lease costs	$ 41,991	$ 26,755	$ 19,922
Finance lease costs	5,546	2,414	1,716
Variable and short-term lease costs	33,475	24,151	13,726
Total lease costs (a)	$ 81,012	$ 53,320	$ 35,364

(a) Includes drilling rig lease costs capitalized to property, plant and equipment of $50.5 million, $40.8 million and $25.4 million, respectively, of which $33.1 million, $24.5 million and $17.7 million, respectively, were operating lease costs for the years ended December 31, 2024, 2023 and 2022.

For the years ended December 31, 2024, 2023 and 2022, cash paid for operating lease liabilities and reported in net cash provided by operating activities in the Statements of Consolidated Cash Flows was $13.6 million, $10.1 million and $10.3 million, respectively. For the years ended December 31, 2024, 2023 and 2022, cash paid for finance lease liabilities and reported in net cash used in financing activities in the Statements of Consolidated Cash Flows was $4.2 million, $2.3 million and $1.8 million, respectively.

For the Company's operating leases, as of December 31, 2024, 2023 and 2022, the weighted average remaining term was 3.4 years, 1.6 years and 1.8 years, respectively, and the weighted average discount rate was 5.3%, 4.7% and 4.5%, respectively. For the Company's finance leases, as of December 31, 2024, 2023 and 2022, the weighted average remaining term was 6.8 years, 3.8 years and 3.3 years, respectively, and the weighted average discount rate was 5.1%, 4.8% and 3.9%, 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. The following table summarizes the Company's right-of-use assets and lease liabilities.

	December 31, 2024	December 31, 2023
	(Thousands)	
Right-of-Use Assets		
Operating	$ 60,496	$ 42,338
Finance	34,803	6,494
Total right-of-use assets	$ 95,299	$ 48,832
Lease Liabilities		
Current lease liabilities		
Operating	$ 36,275	$ 43,891
Finance	5,603	2,489
Total current lease liabilities	41,878	46,380
Noncurrent lease liabilities		
Operating	29,391	8,443
Finance	29,263	3,754
Total noncurrent lease liabilities	58,654	12,197
Total lease liabilities	$ 100,532	$ 58,577

The following table summarizes the Company's lease payment obligations as of December 31, 2024.

	Operating	Finance	Total
	(Thousands)		
2025	$ 38,592	$ 7,192	$ 45,784
2026	8,289	6,420	14,709
2027	7,623	6,057	13,680
2028	6,480	4,806	11,286
2029	5,804	4,523	10,327
Thereafter	5,207	12,126	17,333
Total lease payment obligations	71,995	41,124	113,119
Less: Imputed interest	6,329	6,258	12,587
Present value of lease liabilities	$ 65,666	$ 34,866	$ 100,532

15. Commitments and Contingencies

Purchase Obligations

The Company has commitments to pay demand charges under long-term contracts and binding precedent agreements with various pipelines as well as charges for processing capacity to extract heavier liquid hydrocarbons from the natural gas stream. Aggregate future payments for such commitments as of December 31, 2024 were $13.6 billion, composed of $1.1 billion in 2025, $1.1 billion in 2026, $1.0 billion in 2027, $0.9 billion in 2028, $0.9 billion in 2029 and $8.6 billion thereafter.

In addition, the Company has commitments to pay for services related to its operations, including electric hydraulic fracturing services, and purchase equipment, materials and sand. Aggregate future payments for such commitments as of December 31, 2024 were $494.3 million, composed of $219.9 million in 2025, $148.4 million in 2026, $88.1 million in 2027 and $37.9 million in 2028.

See Note 14 for a summary of undiscounted future cash flows owed to lessors by the Company as lessee pursuant to contractual agreements in effect as of December 31, 2024.

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, and certain former executives and current and former board members of EQT (the Securities Class Action). The complaint alleges that certain statements made by EQT 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 stock price in 2018 and 2019.

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 against EQT and certain former executives and current and former board members of EQT 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.

Following the commencement of the Securities Class Action, the parties engaged in fact and expert discovery. In June 2024, the discovery phase of the Securities Class Action was completed. On June 27, 2024, the parties to the Securities Class Action participated in a mediation (the Mediation), which did not result in resolution. A trial date for the Securities Class Action has not been determined.

In the second quarter of 2024, the Company recorded an accrual for estimated loss contingencies associated with the Securities Class Action in an amount equal to the settlement offer the Company tendered at the Mediation. Due to the inherent subjectivity of the assessments and unpredictability of outcomes of legal proceedings, the amount accrued for estimated losses associated with the Securities Class Action may not represent the ultimate loss to the Company, and the Company's exposure and ultimate losses may be higher, and possibly significantly so, than the amounts accrued or estimated. The amount accrued for such estimated losses is based on the Company's analysis of currently available information and is subject to significant judgment and a variety of assumptions and uncertainties and may change as new information is obtained. While the parties have completed discovery, various motions, including dispositive motions, have not yet been decided, 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. Given these uncertainties, the Company is unable at this time to reasonably estimate the range of possible additional losses above the amount accrued. The Company disputes the claims asserted in the Securities Class Action and related litigation and believes it has meritorious defenses, 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 $10.3 million was recorded in other liabilities and credits in the Consolidated Balance Sheet as of December 31, 2024.

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.

16. Concentrations of Credit Risk

Revenues and related accounts receivable from the Company's Production segment 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, including 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 is not dependent 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.

As of December 31, 2024 and 2023, approximately 96% and 93%, respectively, of the Company's sales of natural gas, NGLs and oil accounts receivable balances represented 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, 2024, 2023 and 2022.

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, 2024, 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, 2024, 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.

Revenues and related accounts receivable from the Company's Gathering and Transmission segments operations are generated predominantly from the transportation of natural gas in Pennsylvania and West Virginia. The Company is not dependent on any single third-party customer and believes that the loss of any one customer would not have an adverse effect on the Company's ability to generate revenues through its gathering, transmission and storage services.

17. 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, 2024	December 31, 2023
	(Thousands)	
Capitalized costs		
Proved properties	$ 31,986,473	$ 30,471,164
Unproved properties	1,563,440	2,039,431
Total capitalized costs	33,549,913	32,510,595
Less: Accumulated depreciation and depletion	12,489,317	10,734,099
Net capitalized costs	$ 21,060,596	$ 21,776,496

	Years Ended December 31,		
	2024	2023	2022
		(Thousands)	
Costs incurred (a)			
Property acquisition:			
Proved properties (b)	$ 410,805	$ 4,142,621	$ 82,276
Unproved properties (c)	98,007	575,130	113,523
Exploration	2,735	3,330	3,438
Development	1,848,000	1,782,428	1,298,665

(a) Amounts for all years presented exclude costs for facilities, information technology and other corporate items. In addition, amounts for 2024 exclude midstream assets. Amounts for 2023 and 2022 include costs for midstream assets.

(b) Amounts in 2024 include $267.7 million and $74.7 million for wells and leases, respectively, received as consideration for the First NEPA Non-Operated Asset Divestiture. See Note 7. 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. Amounts in 2022 include $40.5 million for leases acquired in the 2022 Asset Acquisition. See Note 6.

(c) Amounts in 2024 include $10.8 million for unproved properties received as consideration for the First NEPA Non-Operated Asset Divestiture. See Note 7. 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. See Note 6.

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,		
	2024	2023	2022
		(Thousands)	
Sales of natural gas, NGLs and oil	$ 4,934,366	$ 5,044,768	$ 12,114,168
Transportation and processing	1,915,616	2,157,260	2,116,976
Production	377,007	254,700	300,985
Operating and maintenance	37,951	—	—
Exploration	2,735	3,330	3,438
Depreciation and depletion	2,016,670	1,732,142	1,665,962
(Gain) loss on sale/exchange of long-lived assets	(764,431)	17,445	(8,446)
Impairment and expiration of leases	97,368	109,421	176,606
Income tax expense	316,377	187,463	1,987,323
Results of operations from producing activities, excluding corporate overhead	$ 935,073	$ 583,007	$ 5,871,324

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 has 22 years of experience in the oil and gas industry and holds a bachelor's degree in petroleum engineering from the University of Oklahoma, a master's degree in business administration from Oklahoma City University and a Juris Doctor from the Oklahoma City University School of Law. 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, 2024. 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 Mbbl to approximately six million cubic feet (MMcf).

	Years Ended December 31,		
	2024	**2023**	**2022**
		(MMcfe)	
Natural gas, NGLs and oil			
Proved developed and undeveloped reserves:			
Balance at January 1	27,596,694	25,002,589	24,961,499
Revision of previous estimates	(1,079,677)	(1,402,039)	(654,618)
Purchase of hydrocarbons in place	413,040	2,600,667	141,038
Sale of natural gas in place	(1,562,849)	—	—
Extensions, discoveries and other additions	3,125,620	3,411,750	2,494,713
Production	(2,228,159)	(2,016,273)	(1,940,043)
Balance at December 31	26,264,669	27,596,694	25,002,589
Proved developed reserves:			
Balance at January 1	19,558,176	17,513,645	17,218,655
Balance at December 31	18,804,929	19,558,176	17,513,645
Proved undeveloped reserves:			
Balance at January 1	8,038,518	7,488,944	7,742,844
Balance at December 31	7,459,740	8,038,518	7,488,944

	Years Ended December 31,		
	2024	2023	2022
		(MMcf)	
Natural gas			
Proved developed and undeveloped reserves:			
Balance at January 1	25,795,134	23,824,887	23,523,665
Revision of previous estimates	(917,676)	(1,461,305)	(432,315)
Purchase of natural gas in place	395,423	2,012,159	141,038
Sale of natural gas in place	(1,562,849)	—	—
Extensions, discoveries and other additions	2,921,638	3,326,736	2,434,543
Production	(2,086,441)	(1,907,343)	(1,842,044)
Balance at December 31	24,545,229	25,795,134	23,824,887
Proved developed reserves:			
Balance at January 1	18,186,432	16,541,017	16,152,083
Balance at December 31	17,440,191	18,186,432	16,541,017
Proved undeveloped reserves:			
Balance at January 1	7,608,702	7,283,870	7,371,582
Balance at December 31	7,105,038	7,608,702	7,283,870

	Years Ended December 31,		
	2024	2023	2022
		(Mbbl)	
NGLs			
Proved developed and undeveloped reserves:			
Balance at January 1	285,345	186,141	225,792
Revision of previous estimates	(24,332)	11,558	(33,955)
Purchase of NGLs in place	2,529	90,604	—
Extensions, discoveries and other additions	30,391	13,592	9,610
Production	(22,025)	(16,550)	(15,306)
Balance at December 31	271,908	285,345	186,141
Proved developed reserves:			
Balance at January 1	218,523	154,921	169,781
Balance at December 31	217,786	218,523	154,921
Proved undeveloped reserves:			
Balance at January 1	66,822	31,220	56,011
Balance at December 31	54,122	66,822	31,220

	Years Ended December 31,		
	2024	2023	2022
	(Mbbl)		
Oil			
Proved developed and undeveloped reserves:			
Balance at January 1	14,915	10,142	13,846
Revision of previous estimates	(2,669)	(1,680)	(3,095)
Purchase of oil in place	407	7,481	—
Extensions, discoveries and other additions	3,606	577	418
Production	(1,595)	(1,605)	(1,027)
Balance at December 31	14,664	14,915	10,142
Proved developed reserves:			
Balance at January 1	10,101	7,183	7,981
Balance at December 31	9,669	10,101	7,183
Proved undeveloped reserves:			
Balance at January 1	4,814	2,959	5,865
Balance at December 31	4,995	4,814	2,959

The change in reserves during the year ended December 31, 2024 resulted from the following:

- Conversions of 2,637 billion cubic feet equivalent (Bcfe) of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,126 Bcfe, which exceeded 2024 production of 2,228 Bcfe. Extensions, discoveries and other additions included an increase of 2,414 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2024 reserve development that expanded the number of the Company's proven locations and additions to the Company's five-year drilling plan, 498 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 157 Bcfe from the extension of lateral lengths of proved undeveloped reserves and 57 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 925 Bcfe related to proved undeveloped locations that are no longer expected to be developed as proved reserves within five years of initial booking primarily as a result of development schedule changes.
- Negative revisions of 87 Bcfe to proved undeveloped locations primarily related to revisions to lateral lengths and type curves.
- Positive revisions to proved undeveloped locations of 189 Bcfe due primarily to changes in ownership interests.
- Negative revisions of 65 Bcfe primarily from proved developed locations as a result of negative curve revisions.
- Negative revisions of 192 Bcfe from proved developed locations as a result of lower pricing, impacting well economics.
- Purchase of hydrocarbons in place of 413 Bcfe in connection with the First NEPA Non-Operated Asset Divestiture described in Note 7.
- Sale of natural gas in place of 1,563 Bcfe in the NEPA Non-Operated Asset Divestitures described in Note 7.

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.

Standardized Measure of Discounted Future Cash Flow

Management cautions that the standardized measure of discounted future net 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,		
	2024	2023	2022
	(Thousands)		
Future cash inflows (a)	$ 44,871,509	$ 52,916,665	$ 140,032,653
Future production costs (b)	(18,979,056)	(24,357,033)	(22,801,652)
Future development costs	(4,352,890)	(4,298,372)	(3,244,211)
Future income tax expenses	(4,445,354)	(5,230,629)	(26,375,241)
Future net cash flow	17,094,209	19,030,631	87,611,549
10% annual discount for estimated timing of cash flows	(9,095,069)	(9,768,282)	(47,547,025)
Standardized measure of discounted future net cash flows	$ 7,999,140	$ 9,262,349	$ 40,064,524

(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,		
	2024	2023	2022
Natural gas for NYMEX ($/MMBtu)	$ 2.130	$ 2.637	$ 6.357
Less regional adjustments ($/MMBtu)	0.741	1.029	1.094
Natural gas price ($/Mcf)	1.468	1.700	5.543
NGLs price ($/Bbl)	29.28	28.44	38.66
Oil for West Texas Intermediate (WTI) ($/Bbl)	76.32	78.21	94.14
Less regional adjustments ($/Bbl)	16.87	14.35	17.31
Oil price ($/Bbl)	59.45	63.86	76.83

(b) Includes approximately $2,553 million, $2,443 million and $2,098 million for future plugging and abandonment costs as of December 31, 2024, 2023 and 2022, 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, 2024 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1,184 million, $1,128 million and $73 million, respectively.

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

	Years Ended December 31,		
	2024	2023	2022
	(Thousands)		
Net sales and transfers of natural gas and oil produced	$ (2,603,792)	$ (2,632,808)	$ (9,696,207)
Net changes in prices, production and development costs	(1,237,271)	(48,739,248)	35,353,172
Extensions, discoveries and improved recovery, net of related costs	464,496	6,347,387	1,798,851
Development costs incurred	1,432,315	1,296,380	902,925
Net purchase of minerals in place	269,453	2,131,567	280,233
Net sale of minerals in place	(692,019)	—	—
Revision of previous estimates	(263,191)	(2,768,922)	(299,423)
Accretion of discount	926,235	4,006,452	1,728,112
Net change in income taxes	411,999	9,190,460	(7,233,051)
Timing and other	28,566	366,557	(51,212)
Net (decrease) increase	(1,263,209)	(30,802,175)	22,783,400
Balance at January 1	9,262,349	40,064,524	17,281,124
Balance at December 31	$ 7,999,140	$ 9,262,349	$ 40,064,524

Following the completion of the Equitrans Midstream Merger as described in Note 6, the Company updated certain of its cost assumptions for estimating its proved reserves to reflect the Company's ownership of the assets acquired in the Equitrans Midstream Merger and the elimination of the gathering, transportation and water service costs from the pre-existing contractual relationships between the Company and Equitrans Midstream, which are treated as intercompany transactions on a consolidated basis. Similarly, the Company updated certain of its future cost assumptions to include the additional expenses required to build and maintain the acquired midstream assets, which are needed to transport the Company's produced gas to the first liquid sales point. Lastly, following the completion of the Midstream Joint Venture Transaction as discussed in Note 8, the Company updated certain of its future cost assumptions to account for changes in the noncontrolling interest ownership of the assets owned by the Midstream Joint Venture. The Company believes that the methodology used in developing these assumptions best reflects the current economic conditions affecting the Company's reserves and gives consideration to the Company's ownership interest in its midstream assets.

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, 2024. In making this assessment, our 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, 2024. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Equitrans Midstream Merger on July 22, 2024. Equitrans Midstream's total assets represented approximately 25% of our total assets at December 31, 2024, and Equitrans Midstream's total operating revenues represented approximately 5% of our total operating revenues for the year ended December 31, 2024.

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

As noted under "Management's Report on Internal Control over Financial Reporting," our management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Equitrans Midstream Merger on July 22, 2024. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. We are in the process of integrating our and Equitrans Midstream's internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed.

Except as noted above, there were no changes in our 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 2024 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, 2024, none of our directors or "officers" (as such term is 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 2025 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the end of our fiscal year ended December 31, 2024:

- 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 19, 2025)."

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 "Investors" link on the main page, followed by the "Governance" heading, then the "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 2025 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the end of our fiscal year ended December 31, 2024:

- 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 2025 annual meeting of shareholders, which is expected to be filed with the SEC within 120 days after the end of our fiscal year ended December 31, 2024.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2024 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), 2009 Long-Term Incentive Plan (2009 LTIP), 2008 Employee Stock Purchase Plan (2008 ESPP), and 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)	4,379,293 (2)	$ 12.14 (3)	18,488,456 (4)
Equity Compensation Plans Not Approved by Shareholders (5)	164,901 (6)	N/A	98,095 (7)
Total	4,544,194	$ 12.14	18,586,551

(1) Consists of the 2020 LTIP, 2019 LTIP, 2014 LTIP, 2009 LTIP, and the 2008 ESPP. Effective as of May 1, 2020, in connection 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) 2,869,536 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 1,375,571 target awards and dividend reinvestments thereon)), (ii) 221,096 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) 41,333 shares subject to outstanding directors' deferred stock units under the 2019 LTIP, inclusive of dividend reinvestments thereon, (v) 195,336 shares subject to outstanding stock options under the 2014 LTIP, (vi) 47,326 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon; and (vii) 4,666 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 2.3 years as of December 31, 2024.

(4) Consists of (i) 18,383,332 shares available for future issuance under the 2020 LTIP and (ii) 105,124 shares available for future issuance under the 2008 ESPP. As of December 31, 2024, no shares were subject to purchase under the 2008 ESPP.

(5) Consists of the 2005 DDCP, which is described below, and the legacy Equitrans Midstream Corporation Directors Deferred Compensation Plan (the Equitrans DDCP).

(6) Consists entirely of shares invested in the EQT common stock fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP and the Equitrans DDCP as of December 31, 2024.

(7) Consists entirely of shares available for future issuance under the 2005 DDCP as of December 31, 2024.

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 2025 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the end of our fiscal year ended December 31, 2024.

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 2025 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the end of our fiscal year ended December 31, 2024.

PART IV

Item 15. Exhibits and Financial Statements Schedules

EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2024

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:					
2024	$ 290,812	$ 21,564	$ —	$ (55,158)	$ 257,218
2023	$ 365,140	$ 12,549	$ —	$ (86,877)	$ 290,812
2022	$ 550,967	$ 869	$ —	$ (186,696)	$ 365,140

See Note 9 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.
2.02+	Agreement and Plan of Merger, dated March 10, 2024, among EQT Corporation, Humpty Merger Sub Inc., Humpty Merger Sub LLC and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on March 11, 2024.
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.
3.01(d)	Articles of Amendment to the Restated Articles of Incorporation of EQT Corporation (effective July 18, 2024).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on July 18, 2024.
3.02(a)	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.
3.02(b)	Amendment to Amended and Restated Bylaws of EQT Corporation (effective July 18, 2024).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on July 22, 2024.
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.
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.

Exhibit	Description	Method of Filing
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 EQT Corporation's 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)	Tenth Supplemental Indenture, dated January 21, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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(f)	Eleventh Supplemental Indenture, dated November 16, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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(g)	Twelfth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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(h)	Thirteenth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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(i)	Fifteenth Supplemental Indenture, dated October 4, 2022, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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(j)	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(k)	Seventeenth Supplemental Indenture, dated January 19, 2024, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 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.
4.04(a)	Indenture, dated August 1, 2014, among EQM Midstream Partners, LP (formerly known as EQT Midstream Partners, LP), as issuer, the subsidiaries of EQM Midstream Partners, LP (formerly known as EQT Midstream Partners, LP) party thereto, and The Bank of New York Mellon Trust Company, N.A., as trustee.	Incorporated herein by reference to Exhibit 4.1 to EQM Midstream Partners, LP's Form 8-K (#001-35574) filed on August 1, 2014.
4.04(b)	Fourth Supplemental Indenture, dated June 25, 2018, between EQM Midstream Partners, LP (formerly known as EQT Midstream Partners, LP) and The Bank of New York Mellon Trust Company, N.A., as trustee, pursuant to which EQM Midstream Partners, LP’s 5.500% Senior Notes due 2028 were issued.	Incorporated herein by reference to Exhibit 4.4 to EQM Midstream Partners, LP's Form 8-K (#001-35574) filed on June 25, 2018.
4.04(c)	Fifth Supplemental Indenture, dated June 25, 2018, between EQM Midstream Partners, LP (formerly known as EQT Midstream Partners, LP) and The Bank of New York Mellon Trust Company, N.A., as trustee, pursuant to which EQM Midstream Partners, LP’s 6.500% Senior Notes due 2048 were issued.	Incorporated herein by reference to Exhibit 4.6 to EQM Midstream Partners, LP's Form 8-K (#001-35574) filed on June 25, 2018.
4.04(d)	Sixth Supplemental Indenture, dated December 30, 2024, between EQM Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to EQM Midstream Partners, LP's 5.500% Senior Notes due 2028 and 6.500% Senior Notes due 2048.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on December 31, 2024.

Exhibit	Description	Method of Filing
4.05	Indenture, dated June 18, 2020, between EQM Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A., as trustee, pursuant to which EQM Midstream Partners, LP's 6.000% Senior Notes due 2025 and 6.500% Senior Notes due 2027 were issued.	Incorporated herein by reference to Exhibit 4.1 to Equitrans Midstream Corporation's Form 8-K (#001-38629) filed on June 18, 2020.
4.06	Indenture, dated January 8, 2021, between EQM Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A., as trustee, pursuant to which EQM Midstream Partners, LP's 4.50% Senior Notes due 2029 and 4.75% Senior Notes due 2031 were issued.	Incorporated herein by reference to Exhibit 4.1 to Equitrans Midstream Corporation's Form 8-K (#001-38629) filed on January 8, 2021.
4.07	Indenture, dated June 7, 2022, between EQM Midstream Partners, LP and U.S. Bank Trust Company, National Association, as trustee, pursuant to which EQM Midstream Partners, LP's 7.500% Senior Notes due 2027 and 7.500% Senior Notes due 2030 were issued.	Incorporated herein by reference to Exhibit 4.1 to Equitrans Midstream Corporation's Form 8-K (#001-38629) filed on June 7, 2022.
4.08	Indenture, dated February 26, 2024, between EQM Midstream Partners, LP and U.S. Bank Trust Company, National Association, as trustee, pursuant to which EQM Midstream Partners, LP's 6.375% Senior Notes due 2029 were issued.	Incorporated herein by reference to Exhibit 4.1 to Equitrans Midstream Corporation's Form 8-K (#001-38629) filed on February 26, 2024.
10.01+	Fourth Amended and Restated Credit Agreement, dated July 22, 2024, 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 July 22, 2024
10.02(a)	Third Amended and Restated Limited Liability Company Agreement of Mountain Valley Pipeline, LLC, dated April 6, 2018, by and among MVP Holdco, LLC, US Marcellus Gas Infrastructure, LLC, WGL Midstream MVP LLC (formerly WGL Midstream, Inc.), Con Edison Gas Pipeline and Storage, LLC, RGC Midstream, LLC and Mountain Valley Pipeline, LLC. Specific items in this exhibit have been redacted, as marked by three asterisks [***], because confidential treatment for those items has been granted by the SEC. The redacted material has been separately filed with the SEC.	Incorporated herein by reference to Exhibit 10.1 to EQM Midstream Partners, LP's Form 10-Q/A (#001-35574) for the quarter ended March 31, 2018.
10.02(b)	First Amendment to Third Amended and Restated Limited Liability Company Agreement of Mountain Valley Pipeline, LLC, dated February 5, 2020, by and among MVP Holdco, LLC, US Marcellus Gas Infrastructure, LLC, WGL Midstream MVP LLC (formerly WGL Midstream, Inc.), Con Edison Gas Pipeline and Storage, LLC, RGC Midstream, LLC and Mountain Valley Pipeline, LLC.	Incorporated herein by reference to Exhibit 10.21(b) to Equitrans Midstream Corporation's Form 10-K (#001-38629) for the year ended December 31, 2019.
10.03(a)+	Contribution Agreement, dated November 22, 2024, among PipeBox LLC, EQM Midstream Partners, LP, EQM Gathering OpCo, LLC, MVP HoldCo, LLC and Pibb Member LLC.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on November 26, 2024.
10.03(b)+	Amended and Restated Limited Liability Company Agreement of PipeBox LLC, dated December 30, 2024.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on December 31, 2024.
10.04+	Credit Agreement, dated December 27, 2024, between EQM Midstream Partners, LP and Royal Bank of Canada, as administrative agent and lender.	Incorporated herein by reference to Exhibit 10.2 to Form 8-K (#001-3551) filed on December 31, 2024.
10.05	Guaranty, dated as of December 27, 2024, by EQT Corporation in favor of Royal Bank of Canada as administrative agent under the Credit Agreement, dated as of December 27, 2024, between EQM Midstream Partners, LP and Royal Bank of Canada.	Incorporated herein by reference to Exhibit 10.3 to Form 8-K (#001-3551) filed on December 31, 2024.
10.06	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.
10.07(a)*	Equitrans Midstream Corporation Amended and Restated Directors' Deferred Compensation Plan.	Incorporated herein by reference to Exhibit 10.18 to Equitrans Midstream Corporation's Form 10-Q (#001-38629) for the quarter ended March 31, 2020.
10.07(b)*	Form of Equitrans Midstream Corporation Director Participant Award Agreement	Incorporated herein by reference to Exhibit 10.10 to Equitrans Midstream Corporation's Form 10-Q (#001-38629) for the quarter ended March 31, 2019.

Exhibit	Description	Method of Filing
10.08(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.
10.08(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.
10.08(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.
10.09(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.
10.09(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.
10.09(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.
10.10(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.
10.10(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.
10.10(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.
10.10(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.
10.10(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.
10.10(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.
10.11(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.
10.11(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.
10.11(c)*	Second Amendment to the EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.3 to Form 8-K (#001-3551) filed on July 22, 2024.
10.12(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.

Exhibit	Description	Method of Filing
10.12(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.
10.13*	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.
10.14(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.
10.14(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.
10.15*	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.
10.16*	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.
10.17(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.
10.17(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.
10.18*	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.
10.19*	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.
10.20(a)*	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated November 13, 2018, between Equitrans Midstream Corporation and Thomas F. Karam.	Incorporated herein by reference to Exhibit 10.9 to Equitrans Midstream Corporation’s Form 8-K (#001-38629) filed on November 13, 2018.
10.20(b)*	First Amendment, dated February 20, 2023, to Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 13, 2018, between Equitrans Midstream Corporation and Thomas F. Karam.	Incorporated herein by reference to Exhibit 10.15(b) to Equitrans Midstream Corporation’s Form 10-K (#001-38629) for the year ended December 31, 2022.
10.20(c)*	Second Amendment, effective September 6, 2023, to Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated November 13, 2018, between Equitrans Midstream Corporation and Thomas F. Karam.	Incorporated herein by reference to Exhibit 10.3 to Equitrans Midstream Corporation’s Form 8-K (#001-38629) filed on September 7, 2023.
10.20(d)*	Transition Agreement, dated September 6, 2023, between Equitrans Midstream Corporation and Thomas F. Karam.	Incorporated herein by reference to Exhibit 10.1 to Equitrans Midstream Corporation’s Form 8-K (#001-38629) filed on September 7, 2023.
10.20(e)*+	Separation Agreement and General Release, dated August 14, 2024, between EQT Corporation and Thomas F. Karam.	Incorporated herein by reference to Exhibit 10.06(e) to Form 10-Q (#001-3551) for the quarter ended September 30, 2024.
10.21*	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.

Exhibit	Description	Method of Filing
10.22(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.
10.22(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.
10.22(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.
10.23*	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.
19+	EQT Corporation Insider Trading Policy	Filed herewith as Exhibit 19.
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.	Incorporated herein by reference to Exhibit 97 to Form 10-K (#001-3551) for the year ended December 31, 2023.
99	Independent Petroleum Engineers' Audit Report.	Filed herewith as Exhibit 99
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 19, 2025

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.

/s/ TOBY Z. RICE Toby Z. Rice (Principal Executive Officer)	President, Chief Executive Officer and Director	February 19, 2025
/s/ JEREMY T. KNOP Jeremy T. Knop (Principal Financial Officer)	Chief Financial Officer	February 19, 2025
/s/ TODD M. JAMES Todd M. James (Principal Accounting Officer)	Chief Accounting Officer	February 19, 2025
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 19, 2025
/s/ LYDIA I. BEEBE Lydia I. Beebe	Chair	February 19, 2025
/s/ LEE M. CANAAN Lee M. Canaan	Director	February 19, 2025
/s/ JANET L. CARRIG Janet L. Carrig	Director	February 19, 2025
/s/ FRANK C. HU Frank C. Hu	Director	February 19, 2025
/s/ KATHRYN J. JACKSON Kathryn J. Jackson	Director	February 19, 2025
/s/ THOMAS F. KARAM Thomas F. Karam	Director	February 19, 2025
/s/ JOHN F. MCCARTNEY John F. McCartney	Director	February 19, 2025
/s/ JAMES T. MCMANUS II James T. McManus II	Director	February 19, 2025
/s/ ANITA M. POWERS Anita M. Powers	Director	February 19, 2025
/s/ DANIEL J. RICE IV Daniel J. Rice IV	Director	February 19, 2025

/s/ ROBERT E. VAGT Robert E. Vagt	Director	February 19, 2025
/s/ HALLIE A. VANDERHIDER Hallie A. Vanderhider	Director	February 19, 2025

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)