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, 2025

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 30, 2025: $34.7 billion

The number of shares of common stock, no par value, of the registrant outstanding (in thousands) as of February 11, 2026: 624,274

DOCUMENTS INCORPORATED BY REFERENCE

EQT Corporation's definitive proxy statement relating to its 2026 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, 2025 and is incorporated by reference into Part III of this Annual Report on Form 10-K to the extent described therein.

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GLOSSARY OF COMMONLY USED TERMS, ABBREVIATIONS AND MEASUREMENTS

Unless the context otherwise indicates, all references in this report to "EQT" 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 instruments to reduce financial exposure to commodity price 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
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 dekatherms
MTPA	=	million tonnes per annum
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 NGLs and liquified natural gas (LNG) volumes and sales; the projected volume and timing of LNG offtake and tolling commitments subject to final investment decisions; potential curtailments and the anticipated volume and duration thereof; 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 and organizational 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 EQT 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 upstream, gathering and transmission operations focused in the Appalachian Basin. As of December 31, 2025, we had 28.0 Tcfe of proved natural gas, NGLs and oil reserves across approximately 2.3 million gross acres and approximately 2,945 miles of pipeline infrastructure. In addition, we own an investment in Series A of Mountain Valley Pipeline, LLC (MVP A), which owns the Mountain Valley Pipeline (MVP Mainline), a 303-mile-long pipeline that spans from Wetzel County, West Virginia to Pittsylvania County, Virginia.

Strategy

Our core business strategy is to be the leading low-cost producer of natural gas with a business model designed to generate durable free cash flow across commodity price cycles. This strategy relies on our substantial inventory of core drilling locations, our vast midstream infrastructure spanning across the Appalachian Basin, our investment grade credit metrics, 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 believe we are well positioned to excel during times of market volatility and to serve growing sources of demand, including power generation, industrial consumption, domestic data center development and LNG exports.

Our operational strategy centers on the execution of large-scale, multi-pad development projects, which we refer to as combo-development. 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, which are synchronized with the timing of our development plan. Our synchronized development plan supports an integrated business model that keeps development costs low and limits our need to hedge future production.

Combo-development also provides meaningful environmental and social benefits when compared to more fragmented development approaches. Our operational strategy is integrated with our sustainability framework, which emphasizes continuous improvement in emissions performance, data quality and transparency, workforce development and stakeholder engagement. By concentrating development activity, combo-development results in fewer well sites, reduced truck traffic, lower fuel consumption, shorter and fewer periods of surface disturbance and reduced incremental midstream construction, contributing to improved safety performance and reduced environmental and community impacts.

Further, our integrated business model provides resilience across pricing environments. In periods of low commodity prices, our midstream assets support durable free cash flow due to their annuity-like nature of generating stable, predictable, long-term revenue. 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. 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.

We believe the benefits of our operating model can be enhanced through select strategic transactions, and, as such, part of our strategy also includes creating value through mergers and acquisitions, divestitures, joint ventures and similar business transactions as well as investing in energy-related opportunities directed at complementing and, in certain cases, diversifying our core business operations.

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. Through disciplined execution of our strategy, we aim to be the operator of choice for our stakeholders while supporting the reliable supply of natural gas to meet domestic needs and growing global demand, in a manner that promotes energy security, affordability and sustainable development.

2025 and Recent Highlights

- Achieved sales volume of 2,382 Bcfe, with an average realized price of $3.19 per Mcfe.
- Generated $5.1 billion of net cash provided by operating activities.
- Delivered on our shareholder return strategy through debt retirements and dividends.
  - Retired $1.4 billion aggregate principal of senior notes.
  - Paid $390 million aggregate dividends to shareholders.
  - Increased the quarterly base dividend by 5% to $0.165 per share ($0.66 per share annualized).
- Increased total proved reserves by 1,782 Bcfe, or 7%, compared to 2024.
- Completed the Olympus Energy Acquisition (defined in Note 11 to the Consolidated Financial Statements).
- In January 2026, exercised our preferential buy-out right to acquire additional interests in MVP A and Series C of Mountain Valley Pipeline, LLC (MVP C) for approximately $200.7 million and $12.5 million, respectively, subject to purchase price adjustments. Of the total consideration for the acquisition of additional interests in MVP A, approximately $98.4 million is expected to be funded by the BXCI Affiliate (defined in Note 9 to the Consolidated Financial Statements). The transaction is expected to close in the first half of 2026, subject to regulatory approvals.

Outlook

In 2026, we expect to spend approximately $2,650 million to $2,850 million on total capital expenditures, allocated as shown below.

	Full Year 2026 (Millions)			
Reserve development	$ 1,630	–	$ 1,710
Land and lease	165	–	185
Other upstream infrastructure	85	–	95
Gathering infrastructure	530	–	580
Transmission infrastructure	20	–	30
Capitalized overhead, capitalized interest and other corporate items	220	–	250
Total (a)	$ 2,650	–	$ 2,850

a. Of the total planned capital expenditures, we expect to allocate approximately $580 million to $640 million to growth projects.

In 2026, we expect to make approximately $70 million to $80 million of capital contributions to our equity method investments, including to Mountain Valley Pipeline, LLC (the MVP Joint Venture). See "Transmission Segment Assets and Operations – MVP Joint Venture" for discussion of our investments in the MVP Joint Venture.

In 2026, we expect our sales volume to be 2,275 Bcfe to 2,375 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 hedging 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

We have three reportable segments consisting of Upstream, Gathering and Transmission. Effective as of December 31, 2025, we renamed our previously reported "Production" segment as the "Upstream" segment to better align with the nature of our operations and our internal reporting framework. This change had no impact on the structure of our internal organization, including the composition of our reportable segments. 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,		
	2025	2024	2023
	(Thousands)		
Operating revenues:			
Upstream (a)	$ 8,024,057	$ 5,009,833	$ 6,896,358
Gathering (b)	1,301,434	749,700	161,395
Transmission (b)	572,252	218,293	—
Total Segment	9,897,743	5,977,826	7,057,753
Intersegment eliminations and other (c)	(1,253,532)	(704,517)	(148,830)
EQT Corporation	$ 8,644,211	$ 5,273,309	$ 6,908,923

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

Upstream 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, 2025		
	Natural Gas	NGLs and Oil	Total
	(Bcf)	(MMbbl)	(Bcfe)
Proved developed reserves	19,237	224	20,581
Proved undeveloped reserves	7,179	48	7,465
Total proved reserves	26,416	272	28,046

91% of our total proved developed reserves, over 99% of our total proved undeveloped reserves and 93% 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, 2025			
	Pennsylvania	West Virginia	Ohio	Total
	(Bcfe)			
Proved developed reserves	13,420	6,295	866	20,581
Proved undeveloped reserves	3,833	3,632	—	7,465
Total proved reserves	17,253	9,927	866	28,046
Gross proved undeveloped drilling locations	204	173	4	381
Net proved undeveloped drilling locations	177	145	—	322

Our 2025 total proved reserves increased by 1,782 Bcfe, or 7%, compared to 2024 due to extensions, discoveries and other additions of 2,445 Bcfe and acquisitions from the Olympus Energy Acquisition of 1,768 Bcfe, partly offset by production of 2,382 Bcfe, negative revisions of previous estimates of 27 Bcfe and decreases from the Non-Core Asset Divestiture (defined in Note 12 to the Consolidated Financial Statements) of 22 Bcfe.

Our 2025 proved undeveloped reserves increased by 5 Bcfe, or 0.1%, compared to 2024. The following table provides a rollforward of our proved undeveloped reserves.

	Proved Undeveloped Reserves
	(Bcfe)
Balance at January 1, 2025	7,460
Conversions into proved developed reserves	(2,380)
Acquisition (a)	565
Revision of previous estimates (b)	(311)
Extensions, discoveries and other additions (c)	2,131
Balance at December 31, 2025	7,465

(a) Composed of proved undeveloped locations acquired in the Olympus Energy Acquisition. See Note 11 to the Consolidated Financial Statements.
(b) Composed of (i) negative revisions of 560 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 42 Bcfe primarily related to revisions to lateral lengths and type curves, partly offset by (iii) positive revisions of 291 Bcfe due primarily to changes in ownership interests.
(c) Composed of (i) 1,998 Bcfe from proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2025 reserve development that expanded the number of our proven locations and additions to our five-year drilling plan and (ii) positive revisions of 133 Bcfe from the extension of lateral lengths of proved undeveloped reserves.

As of December 31, 2025, 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. 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 of discounted future net cash flows (the Standardized Measure).

	Years Ended December 31,		
	2025	2024	2023
	(Millions, unless otherwise noted)		
Future net cash flows	$ 43,263	$ 17,094	$ 19,031
Standardized Measure (a)	21,310	7,999	9,262
PV-10 (a)	25,594	9,844	11,520
Prices, including regional differentials:			
Natural gas price ($/Mcf)	$ 2.749	$ 1.468	$ 1.700
NGLs price ($/Bbl)	26.97	29.28	28.44
Oil price ($/Bbl)	50.72	59.45	63.86

(a) PV-10 is a non-GAAP financial measure. PV-10 is derived from 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.

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

	Years Ended December 31,		
	2025	2024	2023
	(Millions)		
Standardized Measure	$ 21,310	$ 7,999	$ 9,262
Estimated discounted income taxes on future net revenues	4,284	1,845	2,258
PV-10	$ 25,594	$ 9,844	$ 11,520

If the prices we used to calculate the Standardized Measure instead reflected five-year strip pricing as of December 31, 2025 and held constant thereafter using (i) the NYMEX five-year strip adjusted for regional differentials using Texas Eastern Transmission Corp. M-2, Transcontinental Gas Pipe Line, Leidy Line, and Tennessee Gas Pipeline Co., Zone 4-300 Leg for gas and (ii) the NYMEX WTI five-year strip for oil, adjusted for regional differentials consistent with those used in the Standardized Measure, and holding all other assumptions constant, our total proved reserves would be 28,117 Bcfe, the Standardized Measure of our proved reserves would be $24,809 million, the discounted future net cash flows before taxes would be $29,798 million and the average realized product prices weighted by production over the remaining lives of the properties would be $3.132 per Mcf of gas, $24.52 per barrel of NGLs and $44.48 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 4,000 gross locations. At our current drilling pace, these locations are projected to 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.

Upstream Acreage

The majority of our Upstream 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 39% of our total gross acres is developed. We retain deep drilling rights on the majority of our production acreage.

The following table summarizes our Upstream acreage disaggregated by state.

	December 31, 2025			
	Pennsylvania	**West Virginia**	**Ohio**	**Total**
Total gross productive acreage	521,017	271,285	80,063	872,365
Total gross undeveloped acreage	814,312	455,222	117,760	1,387,294
Total gross acreage	1,335,329	726,507	197,823	2,259,659
Total net productive acreage	485,815	250,161	63,413	799,389
Total net undeveloped acreage	795,844	365,777	107,987	1,269,608
Total net acreage	1,281,659	615,938	171,400	2,068,997
Average net revenue interest of proved developed reserves	78.4 %	76.3 %	41.4 %	75.0 %

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, 20,309, 28,255 and 14,997 of our net undeveloped Upstream acreage as of December 31, 2025 will expire in the years ending December 31, 2026, 2027 and 2028, 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, 2025.

	December 31, 2025			
	Pennsylvania	**West Virginia**	**Ohio**	**Total**
Productive wells:				
Total gross productive wells (a)	2,631	1,209	424	4,264
Total net productive wells	2,359	1,137	216	3,712
In-process wells:				
Total gross in-process wells	160	115	2	277
Total net in-process wells	148	109	—	257

(a) We had 101 gross conventional wells in Pennsylvania, 6 gross conventional wells in West Virginia and no gross conventional wells in Ohio. In addition, we had 4 gross operated wells with multiple completions.

Drilling Activity

The following table summarizes our net productive development wells.

	Pennsylvania	**West Virginia**	**Ohio**	**Total**
Year ended December 31, 2025	55	67	3	125
Year ended December 31, 2024	76	44	2	122
Year ended December 31, 2023	91	47	2	140

During the years ended December 31, 2025, 2024 and 2023, we drilled zero net dry development wells. In addition, during the years ended December 31, 2025, 2024 and 2023, we drilled zero exploratory wells.

The following table summarizes the gross and net wells on which we initiated drilling operations (spud) during 2025.

	Pennsylvania	West Virginia	Ohio	Total
Gross wells spud	86	45	9	140
Net wells spud	81	36	4	121

Upstream Sales, Pricing, Commitments and Costs

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

	Pennsylvania	West Virginia	Ohio	Total
		(MMcfe)		
Year ended December 31, 2025	1,460,463	816,857	105,047	2,382,367
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

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, 2025, approximately 49% 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 4.3 Bcf per day of firm pipeline takeaway capacity, including 1.29 Bcf per day of firm pipeline takeaway capacity on MVP Mainline 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 (defined below) once placed into service. We have access to approximately 1.0 Bcf per day of firm processing capacity, including 0.2 Bcf per day of firm processing capacity on the processing facility owned by our Gathering segment. 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,		
	2025	2024	2023
Natural gas ($/Mcf):			
Average sales price, excluding cash settled derivatives	$ 3.13	$ 2.02	$ 2.37
Average sales price, including cash settled derivatives	3.08	2.59	2.68
NGLs, excluding ethane ($/Bbl):			
Average sales price, excluding cash settled derivatives	$ 38.04	$ 39.13	$ 36.39
Average sales price, including cash settled derivatives	38.19	38.83	35.12
Ethane ($/Bbl):			
Average sales price	$ 8.01	$ 6.03	$ 6.00
Oil ($/Bbl):			
Average sales price	$ 49.08	$ 58.67	$ 59.93
Natural gas, NGLs and oil ($/Mcfe):			
Average sales price, excluding cash settled derivatives	$ 3.24	$ 2.21	$ 2.50
Average sales price, including cash settled derivatives	3.19	2.74	2.79

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, 2025.

	Natural Gas	NGLs
	(Bcf)	(Mbbl)
Years ending December 31,		
2026	1,475	13,188
2027	571	5,973
2028	457	4,161
2029	391	3,650
2030	348	3,650
Thereafter	1,543	23,730

We are party to two firm sales agreements under which we have committed to deliver and sell up to an aggregate 1.2 Bcf per day of gas using our capacity on MVP Mainline for up to ten years beginning in 2027. These agreements are subject to conditions that have not yet been satisfied 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.

LNG Offtake and Tolling Commitments. As of December 31, 2025, we have entered into three 20-year LNG offtake agreements for an aggregate 4.5 MTPA of LNG, of which 3.0 MTPA is expected to commence as early as 2030 and 1.5 MTPA expected to commence in 2031. In addition, we have entered into a 20-year LNG tolling agreement for up to 2.0 MTPA of capacity expected to commence no earlier than 2030. Of the capacity that may commence in 2030, 1.0 MTPA under the offtake agreements and the 2.0 MTPA tolling commitment relate to projects that have not yet reached final investment decisions to proceed with construction, which require, among other things, the receipt of all necessary authorizations and permits for the project. As a result, the timing, volume or realization of these commitments may be delayed, reduced or may not occur.

Average Production Cost. For the years ended December 31, 2025, 2024 and 2023, lease operating expenses (LOE) per Mcfe were $0.09, $0.09 and $0.07, respectively. For more information on our Upstream segment's operating expenses, refer to "Business Segment Results of Operations – UPSTREAM" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Gathering Segment Assets and Operations

Gathering System

The following table presents information on our gathering system. In addition, we own a processing facility with capacity of 0.2 Bcf per day.

	December 31, 2025
Gathering pipeline miles	1,995
Compression units	200
Compression horsepower	650,000

Gathering Customers

Our Gathering segment has gathering agreements with our Upstream segment and with third parties. Certain of these agreements grant us the right to elect to gather the entire volume of natural gas produced from wells within specified dedicated acreage. For the year ended December 31, 2025, our Upstream segment accounted for approximately 73% of our gathering system throughput and approximately 76% of our Gathering segment's operating revenues.

As of December 31, 2025, our gathering system had total contracted firm reservation capacity, including contracted MVCs, of approximately 7.8 Bcf per day.

As of December 31, 2025, based on total projected contractual revenues, our firm gathering contracts had weighted average remaining terms of approximately 10 years for third-party contracts and 13 years for affiliate contracts.

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 and Storage System

The following table presents information on our transmission and storage system.

	December 31, 2025
Transmission:	
Pipeline miles	950
Throughput capacity (Bcf per day)	5.0
Interconnect points	8
Compression units	45
Compression horsepower	197,000
Storage:	
Reservoirs	18
Peak withdrawal capacity (Bcf per day)	0.8
Working gas capacity (Bcf)	44

Transmission and Storage Customers

Our Transmission segment has transmission and storage agreements with our Upstream segment and with 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, 2025, our Upstream segment accounted for approximately 69% of our transmission system throughput and approximately 61% of our Transmission segment's operating revenues.

As of December 31, 2025, our transmission and storage system had total contracted firm transmission capacity of approximately 5.7 Bcf per day and total contracted firm storage capacity of 29.8 Bcf.

As of December 31, 2025, based on total projected contractual revenues, our firm transmission and storage contracts had weighted average remaining terms of approximately 10 years for third-party contracts and 13 years for affiliate contracts.

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, 2025, approximately 95% of our Transmission segment's contracted firm transmission capacity was subscribed under negotiated rate agreements. As of December 31, 2025, 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.*

MVP Joint Venture

The MVP Joint Venture is a Delaware series limited liability company formed as a joint venture for the purpose of constructing and owning natural gas assets. The MVP Joint Venture has three series, as follows: Series A (MVP A), which owns MVP Mainline; Series B (MVP B), which owns the MVP Southgate project; and Series C (MVP C), which owns certain assets associated with the MVP Boost project.

MVP A. We own an equity method investment in MVP A, which owns MVP Mainline, a 303-mile long, 42-inch diameter natural gas interstate pipeline with a total capacity of 2.0 Bcf per day that spans from our transmission and storage system in Wetzel County, West Virginia to Pittsylvania County, Virginia and has 3 interconnect points to other interstate pipelines. As of December 31, 2025, based on total projected contractual revenues, MVP Mainline's firm transmission and storage contracts had weighted average remaining terms of approximately 19 years.

MVP B. We own an equity method investment in MVP B, which was formed for the purpose of constructing and owning MVP Southgate, a contemplated 31-mile-long, 30-inch diameter natural gas interstate pipeline with a projected capacity of 0.55 Bcf per day that would extend from the terminus of MVP Mainline in Pittsylvania County, Virginia to new delivery points in Rockingham County, North Carolina (MVP Southgate).

Pending receipt of remaining regulatory approvals, MVP Southgate is expected to be placed into service by mid-2028. 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, of which we will fund our proportionate share through capital contributions to MVP B.

MVP C. We own an equity method investment in MVP C, which was formed on November 1, 2025 for the purpose of constructing and owning certain assets associated with the MVP Boost project, a contemplated project to add compression to MVP Mainline, which is projected to increase the capacity on MVP Mainline by 0.6 Bcf per day (MVP Boost). As designed, MVP Boost would add compression at three existing compressor stations in West Virginia and construct a new compressor station in Virginia.

On October 23, 2025, the MVP Joint Venture applied to the FERC for authorization to construct MVP Boost. Pending receipt of regulatory approvals, MVP Boost is expected to be placed into service by mid-2028. MVP Boost is estimated to have a total cost of approximately $400 million to $540 million, excluding AFUDC, of which we will fund our proportionate share through capital contributions to MVP C.

Seasonality

Generally, but not always, the demand for natural gas (including the demand for our gathering, transmission and storage services) 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 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 (the 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" and "security-based swap dealers" 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. Additional proposals relating to regulations 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 the more significant existing laws, rules and regulations to which our business operations are subject. Although compliance with such laws, rules and regulations increases our capital expenditures and adversely affects our earnings, we believe such regulatory obligations generally do not affect us differently, or to any materially greater or lesser extent, than they affect others in our industry with similar operations and types, quantities and locations of production. As such, we anticipate that compliance with such existing laws, rules and regulations will not have a material adverse effect on our competitive position.

Natural Gas Sales and Transportation. The availability, terms and cost of transportation significantly affect sales of natural gas and oil. The interstate transportation and sale for resale of natural gas and oil 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 natural gas and oil pipeline transportation. The FERC's regulations for interstate natural gas and oil 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 (the NGA) and the Natural Gas Policy Act of 1978 (the 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 (as of February 11, 2026 and adjusted periodically for inflation) 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 or 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, and 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, 2025, approximately 95% of our Transmission segment's contracted firm transmission capacity was subscribed under negotiated rate agreements. 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 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. 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. 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. In September 2025, the FERC terminated the Updated Certificate Policy Statement proceeding. 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.

NGLs and Oil Price Controls and Transportation Rates. Sales prices of NGLs and oil 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 NGLs and oil may be affected by the cost of transporting such products to market. Some of our transportation of NGLs and oil 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 NGLs and oil transportation rates may tend to increase the cost of transporting NGLs and oil 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 (the D.C. 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. In November 2025, the FERC declined to readopt the lower rate established by the January 2022 order on rehearing and withdrew its October 2024 supplemental notice of proposed rulemaking, effectively setting the five-year index level for 2021 through 2026 at the level initially established in 2021. In November 2025, the FERC also issued a notice of proposed rulemaking for the five-year index level for 2026-2031.

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. Although compliance with environmental, safety and health laws and regulations increases our capital expenditures and adversely affects our earnings, we believe such regulatory obligations generally do not affect us differently, or to any materially greater or lesser extent, than they affect others in our industry with similar operations and types, quantities and locations of production. As such, we anticipate that compliance with existing environmental, health and safety regulations will not have a material adverse effect on our competitive position.

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. However, over time, the trend has been for stricter regulation of activities that have the potential to affect the environment.

The following is a summary of the more significant environmental and occupational health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, earnings or business.

<u>Hazardous Substances and Waste Handling.</u> 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 capital expenditures and earnings.

We currently own, lease or operate numerous properties that have been used for natural gas and oil 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 (the CWA), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or 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 (the 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 (the 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. In November 2025, the EPA and the Corps published a proposed rule that would revise regulations defining WOTUS under the CWA. 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 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. 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. In November 2025, the EPA sent the WQC Improvement Rule of Section 401 of the CWA to the White House Office of Management and Budget for interagency review. 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. In June 2025, the Corps published a notice of proposed rulemaking to reissue and modify NWPs, which includes modifications to NWP 12. 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.

<u>Air Emissions.</u> Through the federal Clean Air Act (the 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 from new and modified oil and natural gas production and natural gas processing and transmission facilities. 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. In December 2025, the EPA issued a final rule that extends several compliance deadlines in the 2024 New Source Performance Standards and Emissions Guidelines for OOOOb and OOOOc. 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 natural gas and oil 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 capital expenditures and earnings. 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 first 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. 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. 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 issued an interim final rule withdrawing the NEPA implementing regulations. Also in February 2025, CEQ issued a memorandum to federal agencies and departments providing guidance to agencies establishing or revising their agency-specific NEPA implementing procedures. The guidance document was updated and replaced by a subsequent memorandum issued by CEQ in September 2025. In May 2025, CEQ also withdrew its January 2023 interim guidance to federal agencies regarding consideration of the effects of GHG emissions and climate change when conducting environmental reviews pursuant to NEPA. Additionally, in May 2025, the U.S. Supreme Court held in *Seven County Infrastructure Coalition v. Eagle County* that NEPA is a purely procedural statute affording substantial deference to agencies. Following this decision, in July 2025, a number of federal agencies, including the Department of the Interior, the Department of Transportation, the Corps and the Department of Energy, revised their NEPA implementing regulations and issued interim final rules. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our capital expenditures and earnings.

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 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. In January 2026, the United States withdrew from the Paris Agreement and announced that it would also withdraw from the United Nations Framework Convention on Climate Change. Nonetheless, various state and local governments have publicly committed to furthering the goals of the Paris Agreement and many of these initiatives are expected to continue. The full impact of these actions and initiatives remains uncertain at this time.

In recent years, 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 (the IRA), which included a number of climate-focused spending initiatives. However, portions of the IRA were rescinded or modified by the One Big Beautiful Bill Act (the OBBBA) passed in July 2025. For example, the IRA had instituted 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. In March 2025, a Joint Resolution of Disapproval under the Congressional Review Act disapproved implementing the waste emissions charge, and in July 2025, the OBBBA rescinded unobligated funds from the Methane Emissions Reduction Program and postponed the EPA's imposition of the program's waste emissions charge to calendar year 2034.

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. However, in September 2025, the EPA proposed to permanently remove program obligations from the Greenhouse Gas Reporting Program for most source categories and suspend program obligations for some sources subject to Subpart W until 2034.

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, in February 2025, the D.C. Circuit granted the EPA's motion to hold the litigation in abeyance to allow new EPA leadership to review the underlying rule. In June 2025, the EPA issued a proposed rule that would repeal all GHG emissions standards for new and existing fossil fuel-fired power plants, including the May 2024 rule. Additionally, in February 2026, the EPA issued a pre-publication copy of a final rule to rescind the EPA's 2009 finding that GHGs endanger public health and welfare (the Endangerment Finding). The Endangerment Finding has been the foundation for regulating GHG emissions, and without the Endangerment Finding, the EPA may assert that it lacks authority under the CAA to prescribe emissions standards. The potential impact of the final rule, potential subsequent revisions to existing emission standards and outcome of related litigation remain uncertain.

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 November 2025, Pennsylvania enacted legislation ending the state's participation in RGGI.

Regulations requiring the disclosure of GHG emissions and other climate-related information or information substantiating climate-related claims are also being adopted or proposed at the state level. For example, California has enacted legislation that will ultimately require certain companies that do business in California to publicly disclose certain climate-related information, including their Scopes 1, 2, and 3 GHG emissions, with third party assurance of such data, and climate-related financial risks and related mitigation measures. These laws are subject to ongoing legal challenges and certain requirements are currently enjoined. It is unclear how the litigation process and additional legal developments will impact enforceability of these requirements and the timeline and cost of compliance.

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 and NGLs we produce, gather, process and transport. Consequently, legislation and regulatory programs designed to reduce emissions of methane or other GHGs could have an adverse effect on our earnings and business.

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 earnings or 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.* ending 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 capital expenditures to comply with such regulations. Substantial limitations or fees on methane or other GHG emissions could also adversely affect demand for the natural gas and NGLs we produce, gather, process 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 many 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 (the 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 (the 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. The U.S. Court of Appeals for the Eighth Circuit granted the BLM an initial 60-day stay of the litigation in February 2025, and the case continues to be held in abeyance. In November 2025, the BLM announced it would delay enforcement of two provisions of the April 2024 rule previously scheduled to take effect in December 2025. The relevant provisions imposed measurement device and sampling requirements for flares flowing between 1,050 and 6,000 Mcf/month and required operators to submit Leak Detection and Repair plans to the state BLM office. 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.

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); "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); "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.

We do expect certain compliance costs related to the pipeline safety and maintenance regulations to increase in the future, which could materially impact our future costs of operations and earnings. 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 of up to $272,926 per day for each violation and up to approximately $2.7 million for a related series of violations, in each case as of February 11, 2026. This maximum penalty authority established by statute is 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. Furthermore, the adoption of new laws and regulations could result in significant added costs, delays 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 Act of 2020" (the PIPES Act), which reauthorized the federal pipeline safety program that expired in 2019. The PIPES Act identifies areas where Congress believed additional oversight, research or regulation 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 advanced 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 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 (the 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 (the 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 (the 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 April 2025, the Solicitor for the Department of the Interior reinstated a 2017 legal opinion finding that unintentional or incidental injury or death of migratory birds was not prohibited under the MBTA. Also in April 2025, the FWS and the National Marine Fisheries Service issued a notice of proposed rulemaking to rescind the regulatory definition of "harm" included in their respective ESA regulations. 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 upstream 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 earnings, business or operations.

See Note 13 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Human Capital Resources

As of December 31, 2025, we had 1,523 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, 76% are male and 24% are female. In addition, 94% of our employees reside in Pennsylvania, West Virginia, Texas or Ohio, and approximately 56% work remotely.

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 Reports 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, https://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, https://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, https://EQT.com, or our investor relations website to expedite public access to information regarding the Company 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.

Internet addresses included in this Annual Report on Form 10-K are included 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

EQT is 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 make an investment in us speculative or risky and 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 EQT common stock or other securities could decline.

Risks Associated with Natural Gas Upstream, 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 inefficiency. 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 or 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, particularly on steel and aluminum);
- 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 injury, significant damage to property or environmental contamination. Most notably, certain of these risks have been realized in the construction of MVP Mainline, 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 MVP Mainline, MVP Southgate and MVP Boost.

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 could 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 in Venezuela, Russia and Ukraine, and 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 upstream, midstream and processing activities, cause us to incur significant costs in preparing for or responding to those effects, or otherwise adversely affect our business.

Many 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. As of December 31, 2025, approximately 5% 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, 2025, 2024 and 2023, we recorded impairment and expiration of leases of $51.2 million, $97.4 million and $109.4 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. It is possible that Congress may amend Section 7 of the NGA to 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 inefficiency, 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 as of December 31, 2025), changes in natural gas prices have a 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 $9.86 per MMBtu to a low of $2.65 per MMBtu between the period from January 1, 2025 through December 31, 2025, and the daily spot prices for NYMEX WTI oil ranged from a high of $80.73 per barrel to a low of $55.44 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 upstream 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 modeling. 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 prices.

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 EQT common stock, which could negatively impact the price of EQT 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 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, 2025, approximately 95% of our Transmission segment's contracted firm transmission capacity was subscribed under negotiated rate agreements. 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 in and relating to Venezuela, Russia and Ukraine, and 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, to divest themselves of fossil fuel equities and limit funding and insurance coverage to companies engaged in the extraction of fossil fuel reserves, which if successful, could adversely affect the demand and price of our securities and make it more difficult or expensive to secure funding for our activities. 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 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 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, 2025, we had $7.8 billion of debt outstanding, and we may incur additional indebtedness in the future. Increases in our level of indebtedness may:

- require us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for 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 11, 2026, our senior notes were rated "Baa3" with a "Stable" outlook by Moody's Investors Services (Moody's), "BBB–" with a "Stable" outlook by Standard & Poor's Ratings Service (S&P) and "BBB–" with a "Stable" outlook by Fitch Ratings Service (Fitch). Although we are not aware of any current plans of Moody's, S&P or Fitch to downgrade its rating of our senior notes, we cannot be assured that one or more of these rating agencies will not downgrade or withdraw entirely its rating of our senior notes. Low prices for natural gas, NGLs and oil, an increase in the level of our indebtedness or other factors may result in Moody's, S&P or Fitch downgrading its rating of our senior notes. Changes in credit ratings may affect our access to the capital markets, the cost of short-term debt through interest rates and fees under our lines of credit, the interest rate on our 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 Midstream, LLC's (Eureka) revolving credit facility and certain of our 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 our 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. 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. In addition, we are pursuing opportunities geared at enhancing our core operational strategy, including LNG exports, midstream growth projects, the development of data centers and other energy-adjacent or infrastructure-oriented initiatives, as well as sustainability and energy transition initiatives. We have allocated a substantial portion of our financial, human capital and other resources to pursuing our strategy and these initiatives, including investing in new technologies and equipment, restructuring our workforce, building and acquiring new infrastructure, entering into new commercial arrangements, and pursuing projects that may involve new markets, counterparties, regulatory regimes and execution risks. We may not realize some or any of the anticipated strategic, financial, operational, environmental and other anticipated benefits from our operational strategy or strategic initiatives and the corresponding investments we have made in pursuing such opportunities. Our strategic initiatives may expose us to risks that differ from or exceed those associated with our traditional operations. Such projects may be delayed, cost more than expected, fail to reach final investment decisions, fail to achieve commercial operations, or be terminated altogether, and even if completed, may not generate the expected returns or cash flows.

Additionally, we cannot be certain that we will be able to successfully execute combo-development projects, LNG export initiatives, midstream growth projects, data center development or other strategic projects at the pace and scale that we project, which may delay or reduce our production, reserves, revenues or expected benefits therefrom. 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 plans, 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, as well as evolving geopolitical unrest in other parts of the world, 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. 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 and sustainability 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 and sustainability 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 and sustainability matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG or sustainability 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 sustainability 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 sustainability strategy, including any climate or other sustainability 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 and sustainability-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 and sustainability-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.

In addition, regulations requiring the disclosure of GHG emissions and other climate-related information or information substantiating climate-related claims are being adopted or proposed at the state level (e.g., although subject to ongoing legal challenges and certain requirements are currently enjoined, California has enacted legislation that will ultimately require certain companies that do business in California to disclose certain climate-related information, with third-party assurance of such data, and climate-related financial risks and related mitigation measures). If we become subject to such regulations, we may incur additional compliance and reporting costs, which 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 systems service.

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. For example, 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. 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. However, in February 2026, the EPA issued a pre-publication copy of a final rule to rescind the Endangerment Finding, which has been the foundation for regulating GHG emissions. Without the Endangerment Finding, the EPA may assert that it lacks authority under the CAA to prescribe emissions standards. The potential impact of the final rule, potential subsequent revisions to existing emission standards, and outcome of related litigation remain uncertain. See Item 1., "Business – Regulation – Environmental, Health and Safety Regulations-Climate Change and Regulation of Methane and Other Greenhouse Gas Emissions" for more information regarding laws and regulations relating to emissions of methane and other GHGs.

At the international level, in December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change 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. In January 2026, the United States withdrew from the Paris Agreement and announced that it will be withdrawing from the United Nations Framework Convention on Climate Change. Nonetheless, various state and local governments have publicly committed to furthering the goals of the Paris Agreement and many of these initiatives are expected to continue. The full impact of these actions and initiatives remains uncertain at this time. See Item 1., "Business – Regulation – Environmental, Health and Safety Regulations-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 systems service. 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 systems service, 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 MVP Mainline, 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 MVP Southgate, MVP Boost and/or other expansions or extensions of MVP Mainline, 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 MVP Mainline, MVP Southgate and MVP Boost. 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 MVP Mainline, MVP Southgate, MVP Boost 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 MVP Mainline. 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 MVP Mainline 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 MVP Mainline, MVP Southgate and MVP Boost.

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 MVP Mainline. Opposition is ongoing regarding MVP Southgate and is expected for future projects, including any expansions of MVP Mainline. 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-Risks Associated with Strategic Transactions – *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 upstream 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 injury, 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, 2025, 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, 2025, approximately 95% 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 Mainline). Such delays, refusals, losses of permits, or resulting modifications to projects, certain of which was experienced with respect to MVP Mainline and the originally certificated MVP Southgate, 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 (as of February 11, 2026 and 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 the PHMSA, and certain state agencies certificated by the 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, the 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 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 – Regulation of Our Operations," 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 upstream 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 – Environmental, Health and Safety Regulations-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 upstream and midstream activities. This limits our ability to operate in those areas and can intensify competition 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. 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, 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 Holdings) and the Midstream Joint Venture (defined in Note 9 to the Consolidated Financial Statements), 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 2025. 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 Audit Committee receives a regular quarterly report regarding cybersecurity matters and our enterprise cybersecurity program. This report is presented to the Audit Committee by our Chief Information Officer or our Vice President, Information Technology.

Our Enterprise Risk Committee has delegated to our Chief Information Officer primary responsibility for identifying, assessing and managing cybersecurity-related risks. During our Chief Information Officer's sabbatical from September 2025 to the beginning of February 2026, our Vice President, Information Technology, who reports directly to our Chief Information Officer, assumed such responsibility and consulted with our Chief Information Officer as he deemed appropriate. 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 20 years of information technology experience within the energy industry.

Our Information Security team, led by our Vice President, Information Technology 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. Our Vice President, Information Technology, has served in his current role since 2019 and has over 25 years of information technology experience. He is responsible for our enterprise technology strategy and operations, including infrastructure, applications, cybersecurity, and data platforms, and previously served as Director of IT Operations at Rice Energy Inc. for four years prior to joining EQT.

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, Washington D.C., 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 the Pratt Storage Field assets of Equitrans, L.P., one of our subsidiaries. Following the explosion, the Pennsylvania Department of Environmental Protection (the 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 the PHMSA investigations are still open.

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 March 4, 2025, Equitrans, L.P. was granted an additional extension of time, until July 31, 2025, to complete the plugging of the Hupp Well, and, on July 21, 2025, the FERC further extended the time period until January 31, 2026. Plugging operations were completed in advance of the January 31, 2026 deadline, and Equitrans L.P. plans to complete formal 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 Corporation (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. The corrective measures in the May 2023 consent order with the PHMSA have been completed, all wells at the Rager Mountain Facility have returned to service, and on January 9, 2026, we submitted a request to the PHMSA that the consent order be terminated.

On October 17, 2025, the PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty pertaining to this matter, pursuant to which the PHMSA recommended assessing a civil penalty of $939,000. We expect that the resolution of this matter, including the payment of the civil penalty, will not have a material adverse impact on our financial condition, results of operations or liquidity.

Additionally, on July 24, 2025, the Pennsylvania Fifty-First Statewide Investigating Grand Jury returned four criminal charges against Equitrans, L.P., consisting of one violation of the Air Pollution Control Act (35 P.S. 4009(b)(1)) and three violations of the Clean Streams Law (35 P.S. 691.602(b); 35 P.S. 691.401; and 35 P.S. 691.611). All charges are second degree misdemeanors. In its complaint (the Rager Complaint), the Commonwealth of Pennsylvania alleges that from November 6, 2022, to November 19, 2022, Equitrans, L.P. negligently caused air pollution and brine water to emit and discharge into the air, groundwater, and wetlands around the George L. Reade #1 Well, without first obtaining a permit from the PADEP. The Rager 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.

Item 4. Mine Safety Disclosures

Not Applicable.

Information about Our Executive Officers (as of February 18, 2026)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
J.E.B. Bolen (47)	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 (47)	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 (48)	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 (47)	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 (43)	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 (45)	Chief Legal and Policy Officer (2019)	Mr. Jordan was appointed as Chief Legal and Policy Officer of EQT Corporation in October 2024. 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 (37)	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 (44)	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.

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

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

As of February 11, 2026, there were 2,914 shareholders of record of EQT common stock.

On February 5, 2026, our Board of Directors declared a quarterly cash dividend of $0.165 per share of EQT common stock, payable on March 2, 2026, to shareholders of record at the close of business on February 17, 2026.

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 Equity Securities

None.

Issuer Purchases of Equity Securities

We did not repurchase any equity securities registered under Section 12 of the Exchange Act during the fourth quarter of 2025.

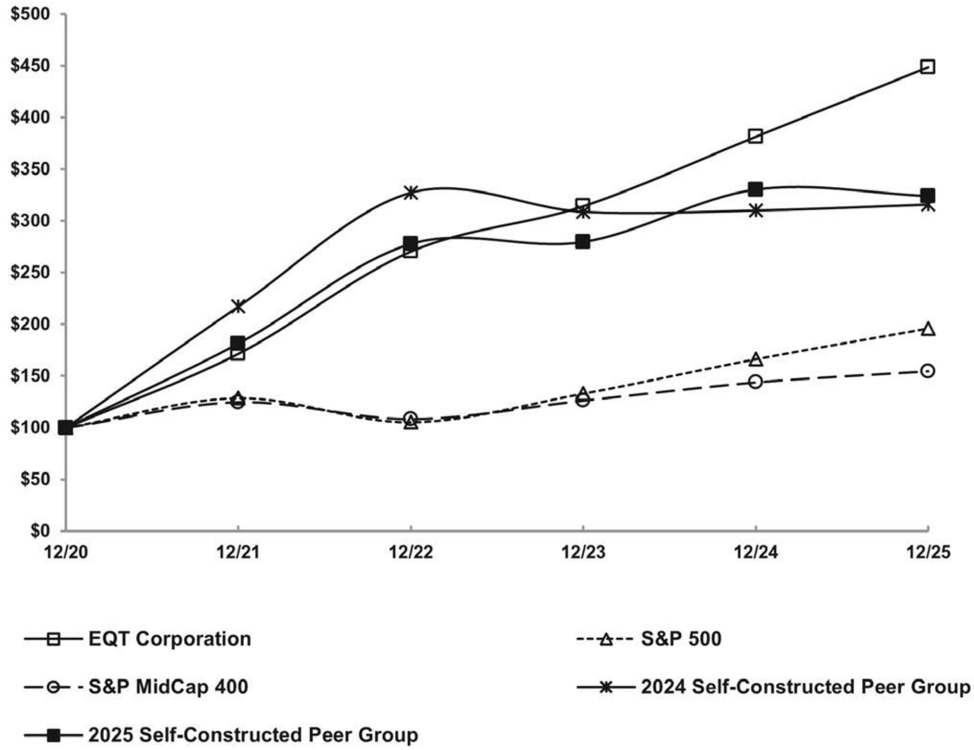
On December 13, 2021, we announced that our Board of Directors approved a share repurchase program (the Share Repurchase Program) authorizing us to repurchase shares of EQT's outstanding common stock for an aggregate purchase price of up to $1 billion, excluding fees, commissions and expenses. On September 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 EQT's outstanding common stock for an aggregate purchase price of up to $2 billion, excluding fees, commissions and expenses. Repurchases under the Share Repurchase Program may be made from time to time in amounts and at prices we deem appropriate and will be subject to a variety of factors, including the market price of EQT's common stock, general market and economic conditions, applicable legal requirements and other considerations. The Share Repurchase Program was originally scheduled to expire on December 31, 2023; however, on April 26, 2023, we announced that our Board of Directors approved a one-year extension of the Share Repurchase Program. 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 EQT's common stock, general market and economic conditions, applicable legal requirements and other considerations. As of December 31, 2025, 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 EQT 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 2024 Self-Constructed Peer Group and the 2025 Self-Constructed Peer Group, whose company composition is discussed in footnotes (a) and (b), respectively, below. EQT common stock was included in the S&P MidCap 400 Index until October 2022, at which time EQT 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 EQT common stock, in the S&P 500 Index, the S&P MidCap 400 Index and in each of the peer groups on December 31, 2020 and its relative performance is tracked through December 31, 2025. 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, 2024 Self-Constructed Peer Group and 2025 Self-Constructed Peer Group



*$100 invested on 12/31/2020 in stock, index or peer group, including reinvestment of dividends. Fiscal year ended December 31.

	12/20	12/21	12/22	12/23	12/24	12/25
EQT Corporation	$ 100.00	$ 171.60	$ 270.43	$ 314.26	$ 381.45	$ 448.69
S&P 500 Index	100.00	128.71	105.40	133.10	166.40	196.16
S&P MidCap 400 Index	100.00	124.76	108.47	126.29	143.88	154.68
2024 Self-Constructed Peer Group (a)	100.00	217.31	327.46	308.95	310.25	315.95
2025 Self-Constructed Peer Group (b)	100.00	181.38	277.66	279.54	330.20	323.98

(a) 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.

(b) The 2025 Self-Constructed Peer Group includes the following fifteen companies: Antero Resources Corp., Antero Midstream Corp., APA Corp. (US), Coterra Energy Inc., Devon Energy Corp., Diamondback Energy Inc., EOG Resources Inc., Expand Energy Corp., Occidental Petroleum Corp., ONEOK Inc., Ovintiv Inc., Permian Resources Corp., Range Resources Corp., Targa Resources Corp. and Williams Companies Inc. The 2025 Self-Constructed Peer Group is comprised of the companies included in our 2025 performance peer group, 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 2025 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

Olympus Energy Acquisition

Our results of operation for 2025 reflect our acquisition (the Olympus Energy Acquisition) of certain oil and gas properties and related upstream and midstream assets from Olympus Energy LLC, Hyperion Midstream LLC and Bow & Arrow Land Company LLC (collectively, Olympus Energy), which was completed on July 1, 2025. See Note 11 to the Consolidated Financial Statements for further discussion of the Olympus Energy Acquisition.

Midstream Joint Venture Transaction

Our results of operation for 2025 reflect the impact of the Midstream Joint Venture Transaction (defined in Note 9 to the Consolidated Financial Statements), where we received $3.5 billion of cash consideration from a third-party investor in exchange for a noncontrolling equity interest in the Midstream Joint Venture. The Midstream Joint Venture Transaction was completed on December 30, 2024.

NEPA Non-Operated Asset Divestitures and NEPA Gathering System Acquisition

Beginning May 31, 2024, our results of operations reflect (i) our divestiture (the First NEPA Non-Operated Asset Divestiture) of an undivided 40% interest in our non-operated natural gas assets in Northeast Pennsylvania and (ii) our 100% ownership of the NEPA Gathering System (defined in Note 11 to the Consolidated Financial Statements) following our acquisition of additional ownership interests therein in connection with the NEPA Gathering System Acquisition (defined in Note 11 to the Consolidated Financial Statements) and the First NEPA Non-Operated Asset Divestiture.

In addition, our results of operations for 2025 reflect our 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 our non-operated natural gas assets in Northeast Pennsylvania, which was completed on December 31, 2024. See Note 12 to the Consolidated Financial Statements for further discussion of the NEPA Non-Operated Asset Divestitures.

Equitrans Midstream Merger

Beginning July 22, 2024, our results of operations reflect our operation of the assets acquired in the Equitrans Midstream Merger (defined in Note 11 to the Consolidated Financial Statements).

Following the Equitrans Midstream Merger, the gathering and transmission services previously provided to us by Equitrans Midstream are provided to our Upstream segment by our Gathering and Transmission segments as affiliate transactions. As a result, our Upstream segment's third-party gathering expense decreased and its affiliate transportation and processing expense increased, and our Gathering and Transmission segments' affiliate revenue increased. As the affiliate expense and revenue are eliminated in consolidation, the net impact is a reduction in our consolidated transportation and processing expense.

As a result of the completion of the Equitrans Midstream Merger, our operations expanded from a single operating segment to three discrete operating segments reflecting our three lines of business consisting of Upstream, Gathering and Transmission.

See Note 11 to the Consolidated Financial Statements for further discussion of the Equitrans Midstream Merger.

Trends and Uncertainties

Commodity prices were volatile in 2025, and we expect commodity prices to continue to be volatile in 2026 due to macroeconomic uncertainty, changes to the regulatory environment and geopolitical instability and tensions, including in Venezuela, Russia, Ukraine and 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.

In response to price volatility in the natural gas market and to optimize in-basin pricing, we implement strategic curtailments from time to time to reduce our gross production. During the year ended December 31, 2025, strategic curtailments resulted in decreased sales volumes of approximately 14 Bcfe. Low natural gas prices or volatility in the natural gas market may result in adjustments to our 2026 planned development schedule and/or adjustments to the development schedule of non-operated wells in which we have a working interest. We cannot control or otherwise influence the development schedule of non-operated wells in which we have a working interest. Adjustments to our 2026 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.

On July 4, 2025, President Trump signed the OBBBA into law. See Note 6 to the Consolidated Financial Statements for further discussion of the OBBBA. We expect the enactment of the OBBBA to favorably impact our projected cash income tax obligations over the next five years by deferring the payment of a significant portion of current federal income taxes.

President Trump has also 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 implementation 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. Tariffs on foreign goods and services could result in other countries instituting tariffs on U.S. goods and services, which could impact the demand for and price of natural gas, increase the price of supplies and raw materials that we rely on to conduct our business, and 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.

Consolidated Results of Operations

Net income attributable to EQT Corporation for 2025 was $2,039 million, $3.31 per diluted share, compared to $231 million, $0.45 per diluted share, for 2024. The increase was driven predominantly by higher sales of natural gas, reflecting higher average realized natural gas prices. To a lesser extent, net income also benefited from decreased gathering expense, increased pipeline revenues, decreased transaction costs, increased gains on derivatives and increased equity earnings from the MVP Joint Venture. These favorable impacts were partly offset by gains recognized in 2024 on the NEPA Non-Operated Asset Divestitures as well as higher income tax expense, depreciation and depletion expense and net income attributable to noncontrolling interests.

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, 2024, which is incorporated herein by reference, for discussion and analysis of consolidated results of operations for the year ended December 31, 2023.

See "Average Realized Price Reconciliation" for a discussion and calculation of our average realized price, which is based on our Upstream segment's adjusted operating revenues (Upstream adjusted operating revenues), a non-GAAP supplemental financial measure that has been reconciled to total Upstream 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 Upstream adjusted operating revenues, a non-GAAP supplemental financial measure. Upstream adjusted operating revenues is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Upstream adjusted operating revenues should not be considered as an alternative to total Upstream operating revenues. See "Non-GAAP Financial Measures Reconciliation" for a reconciliation of Upstream adjusted operating revenues to total Upstream operating revenues, the most directly comparable financial measure calculated in accordance with United States generally accepted accounting principles (GAAP).

	Years Ended December 31,	
	2025	2024
	(Thousands, unless otherwise noted)	
NATURAL GAS		
Sales volume (MMcf)	2,238,652	2,086,441
NYMEX price ($/MMBtu)	$ 3.42	$ 2.30
Btu uplift	0.19	0.13
Natural gas price ($/Mcf)	$ 3.61	$ 2.43
Basis ($/Mcf) (a)	$ (0.48)	$ (0.41)
Cash settled basis swaps ($/Mcf)	(0.01)	(0.07)
Average differential, including cash settled basis swaps ($/Mcf)	(0.49)	(0.48)
Average adjusted price ($/Mcf)	3.12	1.95
Cash settled derivatives ($/Mcf)	(0.04)	0.64
Average natural gas price, including cash settled derivatives ($/Mcf)	$ 3.08	$ 2.59
Natural gas sales, including cash settled derivatives	$ 6,888,420	$ 5,401,642
LIQUIDS		
NGLs, excluding ethane:		
Sales volume (MMcfe) (b)	88,478	87,564
Sales volume (Mbbl)	14,746	14,594
NGLs price ($/Bbl)	$ 38.04	$ 39.13
Cash settled derivatives ($/Bbl)	0.15	(0.30)
Average NGLs price, including cash settled derivatives ($/Bbl)	$ 38.19	$ 38.83
NGLs sales, including cash settled derivatives	$ 563,150	$ 566,808
Ethane:		
Sales volume (MMcfe) (b)	44,534	44,586
Sales volume (Mbbl)	7,422	7,431
Ethane price ($/Bbl)	$ 8.01	$ 6.03
Ethane sales	$ 59,447	$ 44,806
Oil:		
Sales volume (MMcfe) (b)	10,703	9,568
Sales volume (Mbbl)	1,784	1,595
Oil price ($/Bbl)	$ 49.08	$ 58.67
Oil sales	$ 87,562	$ 93,551
Total liquids sales volume (MMcfe) (b)	143,715	141,718
Total liquids sales volume (Mbbl)	23,952	23,620
Total liquids sales	$ 710,159	$ 705,165
TOTAL		
Total natural gas and liquids sales, including cash settled derivatives (c)	$ 7,598,579	$ 6,106,807
Total sales volume (MMcfe)	2,382,367	2,228,159
Average realized price ($/Mcfe)	$ 3.19	$ 2.74

(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 Upstream adjusted operating revenues, a non-GAAP supplemental financial measure.

Non-GAAP Financial Measures Reconciliation

The table below reconciles Upstream adjusted operating revenues, a non-GAAP supplemental financial measure, to total Upstream 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 Upstream operating revenues to EQT Corporation operating revenues as reported in the Statements of Consolidated Operations.

Upstream 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. Upstream adjusted operating revenues is defined as total Upstream operating revenues, less the revenue impact of changes in the fair value of derivative instruments prior to settlement and Upstream other revenues. We believe that Upstream 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. Upstream 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 Upstream other revenues, which consists of costs of, and recoveries on, pipeline capacity releases and other revenues.

	Years Ended December 31,	
	2025	2024
	(Thousands, unless otherwise noted)	
Total Upstream operating revenues	$ 8,024,057	$ 5,009,833
(Deduct) add:		
Upstream gain on derivatives	(290,994)	(67,880)
Net cash settlements (paid) received on derivatives (a)	(83,381)	1,217,895
Premiums paid for derivatives that settled during the period	(44,752)	(45,454)
Upstream other revenues	(6,351)	(7,587)
Upstream adjusted operating revenues, a non-GAAP financial measure	$ 7,598,579	$ 6,106,807
Total sales volume (MMcfe)	2,382,367	2,228,159
Average sales price ($/Mcfe)	$ 3.24	$ 2.21
Average realized price ($/Mcfe)	$ 3.19	$ 2.74

(a) Net cash settlements (paid) received on derivatives are included in average realized price but may not be included in operating revenues. For the year ended December 31, 2025, net cash settlements paid on derivatives consisted of net cash settlements paid on NYMEX natural gas hedge positions of approximately $42 million and net cash settlements paid on basis and liquids hedge positions of approximately $41 million. For the year ended December 31, 2024, net cash settlements received on derivatives consisted of net cash settlements received on NYMEX natural gas hedge positions of approximately $1,374 million, partly offset by net cash settlements paid on basis and liquids hedge positions of approximately $157 million.

Business Segment Results of Operations

The following sections present operating income and key operational measures for our three reportable segments of Upstream, Gathering and Transmission. We believe this information provides useful information to investors regarding our financial condition, results of operations and trends and uncertainties. See Note 2 to the Consolidated Financial Statements for financial information by business segment.

Items that are managed on a consolidated basis, including cash and cash equivalents, debt, income taxes and amounts related to our corporate function, and items related to our energy transition initiatives have not been allocated to our reportable segments. These items are discussed under "Other Income Statement Items."

Effective as of December 31, 2025, we renamed our previously reported "Production" segment as the "Upstream" segment to better align with the nature of our operations and our internal reporting framework. This change had no impact on the structure of our internal organization, including the composition of our reportable segments.

Upstream Results of Operations

	Years Ended December 31, 2025	Years Ended December 31, 2024	Change	% Change
	(Thousands, unless otherwise noted)			
Total sales volume (MMcfe)	2,382,367	2,228,159	154,208	6.9
Average daily sales volume (MMcfe/d)	6,527	6,088	439	7.2
Average sales price ($/Mcfe)	$ 3.24	$ 2.21	$ 1.03	46.6
Operating revenues:				
Sales of natural gas, NGLs and oil	$ 7,726,712	$ 4,934,366	$ 2,792,346	56.6
Gain on derivatives	290,994	67,880	223,114	328.7
Other revenues	6,351	7,587	(1,236)	(16.3)
Total operating revenues	8,024,057	5,009,833	3,014,224	60.2
Operating expenses:				
Transportation and processing:				
Gathering	196,594	775,114	(578,520)	(74.6)
Transmission	1,008,438	846,563	161,875	19.1
Processing	327,058	293,939	33,119	11.3
Transportation and processing to affiliate (a)	1,251,365	704,094	547,271	77.7
Total transportation and processing	2,783,455	2,619,710	163,745	6.3
LOE	216,198	196,771	19,427	9.9
Production taxes	172,498	180,236	(7,738)	(4.3)
Exploration	3,601	2,735	866	31.7
Selling, general and administrative (b)	217,803	244,450	(26,647)	(10.9)
Production depletion	2,258,540	2,013,120	245,420	12.2
Other depreciation and depletion	4,565	3,550	1,015	28.6
Gain on sale/exchange of long-lived assets	(31,513)	(764,431)	732,918	(95.9)
Impairment and expiration of leases	50,341	97,368	(47,027)	(48.3)
Other operating expenses	30,438	12,696	17,742	139.7
Total operating expenses	5,705,926	4,606,205	1,099,721	23.9
Operating income	$ 2,318,131	$ 403,628	$ 1,914,503	474.3
Per Unit ($/Mcfe):				
Gathering	$ 0.08	$ 0.35	$ (0.27)	(77.1)
Transmission	0.42	0.38	0.04	10.5
Processing	0.14	0.13	0.01	7.7
Transportation and processing to affiliate (a)	0.53	0.32	0.21	65.6
LOE	0.09	0.09	—	—
Production taxes	0.07	0.08	(0.01)	(12.5)
Selling, general and administrative (b)	0.09	0.11	(0.02)	(18.2)
Production depletion	0.95	0.90	0.05	5.6

(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 for our change in reportable segments from one reportable segment to three reportable segments as the necessary information was 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 increased by approximately $2,792 million for 2025 compared to 2024, reflecting an increase of approximately $2,451 million from higher average sales price and approximately $341 million from increased sales volumes.

Average sales price increased for 2025 compared to 2024 due primarily to a higher NYMEX price, partly offset by lower NGLs price and an unfavorable basis differential.

Sales volume increased for 2025 compared to 2024 primarily as a result of production curtailments in 2024 of 107 Bcfe (compared to production curtailments in 2025 of 14 Bcfe), wells turned-in-line since 2024, sales volume increases of 92 Bcfe from the assets acquired in the Olympus Energy Acquisition and sales volume increases of 26 Bcfe from the assets received as consideration for (net of assets divested in) the First NEPA Non-Operated Asset Divestiture. Increases in sales volume were partly offset by sales volume decreases of 155 Bcfe from the assets divested in the Second NEPA Non-Operated Asset Divestiture.

The increase in sales volume had a favorable impact on per unit costs for 2025 compared to 2024.

Gain on Derivatives. For 2025, we recognized a gain on derivatives of approximately $291 million related primarily to increases in the fair market value of our NYMEX swaps and options of approximately $291 million due to decreases in NYMEX forward prices and increases in the fair market value of our basis and liquids swaps of approximately $45 million, partly offset by premiums paid for derivative settlements of $45 million. 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 $422 million due to decreases in NYMEX forward prices, partly offset by decreases in the fair market value of our basis and liquids swaps of approximately $309 million and premiums paid for derivative settlements of $45 million.

Gathering Expense. Gathering expense decreased on an absolute and per Mcfe basis for 2025 compared to 2024 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 additional interest in the NEPA Gathering System acquired in the NEPA Gathering System Acquisition and First NEPA Non-Operated Asset Divestiture. In addition, gathering expense decreased due to our divestiture of assets in the NEPA Non-Operated Asset Divestitures.

Transmission Expense. Transmission expense increased on an absolute and per Mcfe basis for 2025 compared to 2024 due primarily to capacity charges of approximately $193 million on the MVP Mainline, which entered into service in June 2024, and additional contracted capacity on the Transco pipeline of approximately $33 million, partly offset by capacity released in connection with the NEPA Non-Operated Asset Divestitures of approximately $57 million.

Processing Expense. Processing expense increased on an absolute and per Mcfe basis for 2025 compared to 2024 due primarily to increased production of gas requiring processing from wells turned-in-line since 2024.

Transportation and Processing Expense to Affiliate. Affiliate transportation and processing expense increased on an absolute and per Mcfe basis for 2025 compared to 2024 due primarily to our Gathering segment's ownership of the gathering assets acquired in the Equitrans Midstream Merger and the Olympus Energy Acquisition, our Transmission segment's ownership of the transmission and storage assets acquired in the Equitrans Midstream Merger and our Gathering segment's ownership of additional interest in the NEPA Gathering System acquired in the NEPA Gathering System Acquisition and First NEPA Non-Operated Asset Divestiture.

Production Taxes. Production tax expense decreased on an absolute and per Mcfe basis for 2025 compared to 2024 due to decreased property tax expense of approximately $53 million from lower property tax value based on prior year pricing, partly offset by increased severance tax expense of approximately $35 million from increased sales volume and higher sales prices.

Selling, General and Administrative Expense. Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast for our change in reportable segments; upon the Equitrans Midstream Merger closing date, we adjusted our basis for selling, general and administrative expense allocation for multi-segment reporting. On a consolidated basis, selling, general and administrative expense increased for 2025 compared to 2024 due primarily to higher labor costs driven by increased headcount as well as higher long-term incentive compensation costs as a result of increases in awards outstanding and changes in the fair value of awards.

Production Depletion Expense. Production depletion expense increased on a per Mcfe basis for 2025 compared to 2024 due to higher annual depletion rate. In addition, production depletion expense increased on an absolute basis due to higher sales volumes.

Gain on Sale/Exchange of Long-Lived Assets. During 2025, we recognized a net gain on sale/exchange of long-lived assets of approximately $36 million related to acreage trade transactions. 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 12 to the Consolidated Financial Statements.

Impairment and Expiration of Leases. During 2025 and 2024, we recognized impairment and expiration of leases of approximately $50 million and $97 million, respectively, related to leases that we no longer expect to extend or develop prior to their expiration based on our development plan.

Other Operating Expenses. Other operating expenses increased for 2025 compared to 2024 due primarily to proceeds received in 2024 from business interruption insurance claim recoveries and increased expense from changes in legal and environmental reserves, including settlements. See Note 1 to the Consolidated Financial Statements for a summary of consolidated other operating expenses.

Gathering Results of Operations

	Years Ended December 31,			
	2025	**2024**	**Change**	**% Change**
	(Thousands, unless otherwise noted)			
Gathered volume (BBtu/d):				
Firm capacity (a)	5,407	5,277	130	2
Volumetric-based services (a)	4,788	4,234	554	13
Total gathered volume	10,195	9,511	684	7
Operating revenues:				
Loss on derivatives	$ —	$ (16,763)	$ 16,763	(100)
Firm reservation fee revenue (b)	632,916	313,987	318,929	102
Volumetric-based fee revenue	668,518	452,476	216,042	48
Total operating revenues	1,301,434	749,700	551,734	74
Operating expenses:				
Operating and maintenance	166,990	89,897	77,093	86
Selling, general and administrative (c)	66,642	38,837	27,805	72
Depreciation	212,353	89,513	122,840	137
Gain on sale/exchange of long-lived assets	(29)	(22)	(7)	32
Impairment and expiration of leases	811	—	811	100
Other operating expenses	18,013	—	18,013	100
Total operating expenses	464,780	218,225	246,555	113
Operating income	$ 836,654	$ 531,475	$ 305,179	57

(a) For agreements structured with MVCs, firm capacity includes volumes up to the contractual MVC and volumetric-based services includes volumes in excess of the contractual MVC.
(b) Firm reservation fee revenue included unbilled revenues supported by MVCs of approximately $18.4 million and $4.2 million for the year ended December 31, 2025 and 2024, respectively.
(c) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast for our change in reportable segments from one reportable segment to three reportable segments as the necessary information was not available and the cost to develop such information would be excessive.

Firm Reservation Fee Revenue. Firm reservation fee revenue increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger, which contributed approximately $377 million of additional firm reservation fee revenue in 2025, partly offset by lower revenue of approximately $66 million from the declining rate structures under the gas gathering agreement with our Upstream segment.

Volumetric-Based Fee Revenue. Volumetric-based fee revenue increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger, which contributed approximately $157 million of additional volumetric-based fee revenue in 2025, the gathering assets acquired in the Olympus Energy Acquisition, which contributed approximately $43 million of additional volumetric-based fee revenue in 2025, and increased ownership of the NEPA Gathering System as a result of the NEPA Gathering System Acquisition and the First NEPA Non-Operated Asset Divestiture.

Operating Expenses. Gathering operating expenses increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger. In addition, during 2025, Gathering recognized other operating expenses related to environmental reserves.

Transmission Results of Operations

	Years Ended December 31,			
	2025	2024	Change	% Change
	(Thousands, unless otherwise noted)			
Transmission pipeline throughput (BBtu/d):				
Firm capacity (a)	4,426	3,695	731	20
Interruptible capacity	39	24	15	63
Total transmission pipeline throughput	4,465	3,719	746	20
Average contracted firm transmission reservation commitments (BBtu/d)	5,025	4,779	246	5
Operating revenues:				
Firm reservation fee revenue	$ 435,194	$ 183,088	$ 252,106	138
Volumetric-based fee revenue	137,058	35,205	101,853	289
Total operating revenues	572,252	218,293	353,959	162
Operating expenses:				
Operating and maintenance	58,141	20,496	37,645	184
Selling, general and administrative	37,339	17,183	20,156	117
Depreciation	88,385	33,505	54,880	164
Amortization of intangible assets	13,333	5,901	7,432	126
Loss on sale/exchange of long-lived assets	349	409	(60)	(15)
Other operating expenses	(527)	—	(527)	100
Total operating expenses	197,020	77,494	119,526	154
Operating income	$ 375,232	$ 140,799	$ 234,433	167

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

Firm Reservation Fee Revenue. Firm reservation fee revenue increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger.

Volumetric-Based Fee Revenue. Volumetric-based fee revenue increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger as well as increased throughput.

Operating Expenses. Transmission operating expenses increased for 2025 compared to 2024 due primarily to the timing of the completion of the Equitrans Midstream Merger.

Other Income Statement Items

Other Operating Expenses. Corporate other operating expenses decreased for 2025 compared to 2024 due primarily to decreased acquisition-related transaction costs. During 2025, we recognized approximately $29 million of transaction costs related to the Olympus Energy Acquisition compared to approximately $305 million of transaction costs related to the Equitrans Midstream Merger in 2024. In addition, during 2025 and 2024, we recognized net expense of approximately $134 million and $18 million, respectively, for loss contingencies related to the Securities Class Action (defined in Note 13 to the Consolidated Financial Statements). See Note 1 to the Consolidated Financial Statements for a summary of consolidated other operating expenses.

Income from Investments. Income from investments increased for 2025 compared to 2024 due primarily to higher equity earnings from our investments in the MVP Joint Venture and Laurel Mountain Midstream, LLC of approximately $76 million and $32 million, respectively.

Other Income. During 2024, we received proceeds from insurance claim recoveries of approximately $19 million related to the assets acquired in the Tug Hill and XcL Midstream Acquisition (defined in Note 11 to the Consolidated Financial Statements).

Loss on Debt Extinguishment. Loss on debt extinguishment decreased for 2025 compared to 2024 due to the derecognition of unamortized fair value adjustments and deferred financing costs associated with debt redemptions, which resulted in a gain of approximately $17 million in 2025 compared to a loss of approximately $16 million in 2024. In addition, net cash call premiums paid were approximately $18 million lower in 2025 compared to 2024.

Interest Expense, Net. Net interest expense decreased for 2025 compared to 2024 due primarily to lower interest expense resulting from the repayment of borrowings under EQT's revolving credit facility and the prepayment of term loans outstanding under EQT's unsecured term loan facility, which was prepaid in full and terminated in December 2024. These decreases were partly offset by higher interest expense on the senior notes assumed in connection with the Equitrans Midstream Merger as well as higher capitalized interest associated with the assets acquired in the Equitrans Midstream Merger.

Income Tax Expense. See Note 6 to the Consolidated Financial Statements.

Net Income Attributable to Noncontrolling Interests. Net income attributable to noncontrolling interests in the Midstream Joint Venture increased approximately $263 million for 2025 compared to 2024 as a result of the Midstream Joint Venture Transaction, which was completed in December 2024. In addition, net income attributable to noncontrolling interests in Eureka Holdings increased approximately $11 million due primarily to the timing of the completion of the Equitrans Midstream Merger.

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.

Planned Capital Expenditures, Capital Contributions and Sales Volume

In 2026, we expect to spend approximately $2,650 million to $2,850 million 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 2026 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 2026, we expect to make approximately $70 million to $80 million of capital contributions to our equity method investments, including to the MVP Joint Venture.

In 2026, we expect our sales volume to be 2,275 Bcfe to 2,375 Bcfe.

Material Cash Requirements

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 13 to the Consolidated Financial Statements for a summary of aggregated future payments for these commitments.

We have contractual commitments under our debt agreements, including interest payments and principal repayments. See Note 7 to the Consolidated Financial Statements for a summary of such contractual commitments, including maturity dates.

Through our controlling interest in the Midstream Joint Venture, we are required to distribute available cash flow to the holder of the Midstream Joint Venture's Class B units (Class B Unitholder). See "Financing Activities" below and Note 9 to the Consolidated Financial Statements for further discussion.

In addition, in January 2026, we exercised our preferential buy-out right in accordance with the MVP Joint Venture's limited liability company agreement (the MVP LLC Agreement) to acquire additional equity interests in MVP A and MVP C from an affiliate of Con Edison Gas Pipeline and Storage, LLC. Total consideration for our acquisition of the equity interests in MVP A is approximately $200.7 million, of which $98.4 million is expected to be funded by the BXCI Affiliate, subject to purchase price adjustment. Total consideration for our acquisition of the equity interests in MVP C is approximately $12.5 million, subject to purchase price adjustments. The transaction is expected to close in the first half of 2026, subject to regulatory approvals.

Sources and Uses of Cash

<u>Operating Activities.</u> Net cash provided by operating activities was approximately $5,126 million and $2,827 million for 2025 and 2024, respectively. The increase was due primarily to higher cash operating revenues, lower net cash operating expenses and higher distributions received from our investment in MVP A of approximately $189 million, partly offset by net cash settlements paid on derivatives in 2025 compared to net cash settlements received in 2024.

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."*

<u>Investing Activities.</u> Net cash used in investing activities was approximately $2,845 million and $1,580 million for 2025 and 2024, respectively. The change is attributable primarily to cash proceeds received in 2024 from the NEPA Non-Operated Asset Divestitures. This impact was partly offset by lower cash paid in 2025 for the Olympus Energy Acquisition compared to cash paid in 2024 for the purchase and redemption of the Equitrans Midstream preferred stock (defined in Note 11 to the Consolidated Financial Statements) and for the NEPA Gathering System Acquisition.

The following table summarizes our capital expenditures by segment.

	Years Ended December 31,	
	2025	2024
	(Millions)	
Upstream:		
Reserve development	$ 1,537	$ 1,653
Land and lease	153	156
Other upstream infrastructure	70	71
Capitalized overhead, capitalized interest and other	118	124
Total Upstream	1,878	2,004
Gathering	368	202
Transmission	52	31
Other corporate items	26	29
Total capital expenditures	2,324	2,266
Deduct: Non-cash items (a)	(36)	(12)
Total cash capital expenditures	$ 2,288	$ 2,254

(a) 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 approximately $2,372 million and $1,126 million for 2025 and 2024, respectively. For 2025, the primary uses of financing cash flows were the repayment and retirement of debt, payment of dividends, distributions to the Midstream Joint Venture's Class B Unitholder (see below) and net repayments of revolving credit facility borrowings. For 2024, the primary uses of financing cash flows were the repayment and retirement of debt, repayment of borrowings under the revolving credit facility of our wholly owned subsidiary, EQM Midstream Partners LP, and payment of dividends. In addition, 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 and net borrowings under EQT's revolving credit facility.

We, through our controlling ownership interest in the Midstream Joint Venture, expect to make available cash flow distributions to the Midstream Joint Venture Class B Unitholder at least quarterly. During 2025, the Midstream Joint Venture made distributions of approximately $355 million to its Class B Unitholder. As of December 31, 2025, the remaining amount required to achieve the Base Return (defined and discussed in Note 9 to the Consolidated Financial Statements) was approximately $3.41 billion. See Note 9 to the Consolidated Financial Statements.

On February 5, 2026, our Board of Directors declared a quarterly cash dividend of $0.165 per share of EQT common stock, payable on March 2, 2026, to shareholders of record at the close of business on February 17, 2026.

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

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 and Eureka's revolving credit facilities, 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, 2025, we were in compliance with all provisions and covenants under our debt agreements. See Note 7 to the Consolidated Financial Statements for a discussion of borrowings under EQT's and Eureka's revolving credit facilities.

Security Ratings

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 11, 2026.

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

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 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.

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 11, 2026. 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 2026 (a)	Q2 2026	Q3 2026	Q4 2026	Q1 2027
Hedged Volume (MMDth)	228	127	125	108	9
Hedged Volume (MMDth/d)	2.5	1.4	1.4	1.2	0.1
Calls – Short					
Volume (MMDth)	228	127	125	108	9
Avg. Strike ($/Dth)	$ 6.29	$ 4.94	$ 4.94	$ 5.13	$ 4.25
Puts – Long					
Volume (MMDth)	228	127	125	108	9
Avg. Strike ($/Dth)	$ 4.25	$ 3.50	$ 3.50	$ 3.72	$ 3.30

(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, 2025, we did not have any material off-balance sheet arrangements other than the commitments described in Note 13 to the Consolidated Financial Statements and the MVP B and MVP C guarantees discussed in Note 8 to the Consolidated Financial Statements.

Commitments and Contingencies

See Note 13 to the Consolidated Financial Statements for a discussion of our commitments and contingencies.

Recently Issued Accounting Standards

See Note 1 to the Consolidated Financial Statements for a description of recently issued accounting standards.

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 in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. The following critical accounting estimates, which were reviewed by the Audit Committee of our Board of Directors, relate to our more significant estimates and assumptions used in the preparation of the Consolidated Financial Statements. Actual results could differ from those 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 known reservoirs 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 proved reserve estimates rely on several significant assumptions, including those listed as follows:

- future rates of production and estimated ultimate recoveries of developed and undeveloped reserves;
- our five-year development plan, including the amount and timing of expected development expenditures;
- future liquids recovery in wet-gas areas; and
- commodity prices, production costs and income taxes.

Proved reserve estimates are reassessed annually using geological, reservoir and production performance data. Estimates are prepared by internal engineers and audited by independent engineers. Management evaluates significant changes in development plans, cost structure and operating conditions that could affect reserve quantities.

Revisions may result from changes in, among other things, reservoir performance, development plans, prices, operating costs, economic conditions or governmental restrictions. For example, decreases in prices may reduce certain proved reserves by accelerating the timing at which economic limits are reached. Material changes in proved reserve quantities could affect our depletion rates and, therefore, the Consolidated Financial Statements.

We estimate future net cash flows from proved reserves based on selling prices using the prescribed 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. Future production and development costs are based on current costs with no escalation. Income taxes are based on currently enacted statutory tax rates and available tax deductions and credits.

Estimate changes during 2025 primarily reflected proved reserves acquired as part of the Olympus Energy Acquisition and development schedule refinements. See Note 17 to the Consolidated Financial Statements for additional information on changes to our proved reserve estimates.

We believe oil and gas reserves is a "critical accounting estimate" because changes in proved reserve estimates and the significant assumptions underlying those estimates could materially affect our results of operations or financial position. Based on proved reserves as of December 31, 2025, we estimate that a 1% change in proved reserves would decrease or increase 2026 depletion expense by approximately $11 million and $21 million, respectively, based on current production estimates for 2026.

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 the Consolidated Financial Statements or tax returns. See Notes 1 and 6 to the Consolidated Financial Statements for additional information on our accounting policies for income taxes and the composition of deferred tax assets, valuation allowances and uncertain tax positions.

We believe income taxes is a "critical accounting estimate" because we rely on significant assumptions regarding the likelihood, including whether it is more likely than not, that our deferred tax assets will be recovered from future taxable income and the assessment of the amount of financial statement benefit recorded for uncertain tax positions.

We evaluate deferred tax assets and valuation allowances using all available evidence, both positive and negative, including federal and state taxable income forecasts, state apportionment analyses, reversals of temporary differences, tax planning strategies, prior year carrybacks and the expected utilization of tax credits. We evaluate uncertain tax positions based on the technical merits of each position and the probability of realization.

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, 2025, 2024 and 2023, we estimate that a 1% change in our effective tax rate would increase or decrease income tax expense by approximately $30 million, $3 million and $21 million, respectively.

Derivative Instruments

We use derivative commodity instruments primarily to reduce exposure to commodity price risk associated with future sales of natural gas production. See Note 4 to the Consolidated Financial Statements for a description of our derivative instruments and 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 changes in the market value of our derivative instruments resulting from the volatility of both NYMEX natural gas prices and basis can materially affect our results of operations or financial position. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. The sensitivity of our derivative fair value measurements to changes in natural gas prices is quantified through the hypothetical 10% price change analysis disclosed in Item 7A., "Quantitative and Qualitative Disclosures about Market Risk," which is calculated using a valuation methodology consistent with our derivative fair value measurements.

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 when a loss is probable and the amount can be reasonably estimated. Our contingency estimates rely on assumptions about the likelihood of loss and the ability to reasonably estimate a range of potential outcomes. We evaluate contingencies on an ongoing basis in consultation with legal counsel, considering developments in each matter and the potential range of outcomes. See Note 13 to the Consolidated Financial Statements for information on our contingencies.

We also accrue a liability for asset retirement obligations based on the estimated timing and cost of settlement. For oil and gas wells, the fair value of plugging and abandonment obligations is recorded when the obligation is incurred, which is typically at the time the well is spud. Our asset retirement obligation estimates are based on methodologies and assumptions described in Note 1 to the Consolidated Financial Statements, including assessments of the expected timing and cost of settlement and the discount rates applied to determine the present value of future obligations. Estimate changes during 2025 primarily reflected routine updates to plugging cost inputs. There were no material changes to our estimation methodologies.

We believe contingencies and asset retirement obligations is a "critical accounting estimate" because changes in these estimates and the significant assumptions underlying them could materially affect our results of operations or financial position. Actual losses related to contingencies could differ from our estimates, which may require additional cash expenditures. Changes in the expected timing or amount of asset retirement obligations may require adjustments to the carrying value of our liabilities. An estimate of the sensitivity to changes in these assumptions is not practicable given the number of variables involved.

Business Combinations

In a business combination, the identifiable assets acquired and liabilities assumed are recorded at fair value as of the acquisition date. Goodwill results when the cost of an acquisition exceeds the fair value of the net assets acquired.

During 2025, we completed the Olympus Energy Acquisition. The significant assumptions used to estimate the fair value of assets acquired and liabilities assumed in the Olympus Energy Acquisition are discussed in Note 11 to the Consolidated Financial Statements.

We believe business combinations is a "critical accounting estimate" because the valuation of acquired assets and assumed liabilities requires significant judgment about future events and may rely on inputs that are not observable in the market. Changes in these assumptions could materially affect our results of operations or financial position. An estimate of the sensitivity to changes in these assumptions is not practicable given the number of variables involved.

Long-Lived Assets (Including Property, Plant and Equipment and Intangible Assets)

See Note 1 to the Consolidated Financial Statements for a discussion of our fair value measurements and impairment evaluations for oil and gas properties, midstream assets, other property, plant and equipment (including our assessment of the recoverability of capitalized costs of unproved oil and gas properties) and intangible assets.

Our impairment evaluations for long-lived assets rely on the following significant assumptions, as applicable:

- future natural gas and NGLs sales prices;
- estimated reserve quantities and expected timing of production;
- future operating costs and capital requirements;
- discount rates and inflation assumptions used in estimating the present value of expected future cash flows; and
- operating levels, utilization and other asset-specific performance expectations (e.g., projected gathered and processed volumes and transmission throughput for midstream assets; expected contract utilization for intangible assets related to acquired transmission service agreements).

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying amounts may not be recoverable. We consider indicators such as changes in commodity prices, well performance, expected development activity, operating cost trends, asset utilization levels and asset-specific market conditions. When indicators are present, we estimate recoverable value using income-based and, when appropriate, market-based valuation techniques. There were no indicators of impairment to our material asset groups identified during 2025, 2024 and 2023.

We believe long-lived asset impairment is a "critical accounting estimate" because these evaluations require significant judgment about future events. Changes in these assumptions could materially affect our results of operations or financial position, including the timing or amount of impairment charges. An estimate of the sensitivity to changes in these assumptions is not practicable given the number of variables involved.

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.*"

Investments in Unconsolidated Entities

See Notes 1 and 8 to the Consolidated Financial Statements for a discussion of our accounting policies for investments in unconsolidated entities and the carrying value of our investments.

Our impairment evaluations for investments in unconsolidated entities rely on the following significant assumptions, as applicable:

- expected future cash flows of the investee, including assumptions regarding commodity prices, operating costs and capital requirements;
- the investee’s ability to generate cash flows sufficient to recover our carrying value; and
- market, operational or financial developments that may affect the recoverability of the investment.

We evaluate investments in unconsolidated entities for impairment when events or changes in circumstances indicate that the carrying amounts may not be recoverable. We consider indicators such as changes in the investee's financial condition, operating performance, forecasted cash flows or market environment. When indicators are present, we estimate recoverable value using expected future cash flows or other relevant valuation information. There were no indicators of impairment to our investments in unconsolidated entities identified during 2025, 2024 and 2023.

We believe the impairment of investments in unconsolidated entities is a "critical accounting estimate" because these evaluations require significant judgment regarding the investee's ability to recover its carrying value. Changes in assumptions about the investee’s operating performance, cash flows or market environment could materially affect our results of operations or financial position. An estimate of the sensitivity to changes in these assumptions is not practicable given the number of variables involved.

Goodwill

Goodwill is tested for impairment annually as of October 1 or when events or changes in circumstances indicate the carrying value of a reporting unit may not be recoverable. Indicators of potential impairment may include adverse changes in market conditions, declining operating performance or negative developments in equity or credit markets.

When performed, a quantitative impairment analysis requires judgment in estimating future cash flows, long-term commodity prices, development and operating costs and discount rates used in determining fair value. For 2025, we performed a qualitative assessment and concluded that it was more likely than not that the fair values of our reporting units exceeded their carrying amounts. Because a quantitative test was not performed, no fair value assumptions were developed. See Note 1 to the Consolidated Financial Statements for a discussion of our goodwill impairment assessment process.

We believe goodwill impairment is a "critical accounting estimate" because these evaluations require significant judgment about future events. Although we performed a qualitative assessment for 2025, the determination of fair value in a quantitative test would be sensitive to assumptions related to forecasted cash flows, market conditions, industry factors and discount rates. Changes in these assumptions could materially affect the estimated fair values of our reporting units and the resulting conclusion on impairment. An estimate of the sensitivity to changes in these assumptions is not practicable given the number of variables involved.

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, 2025 and 2024 would increase the fair value of our natural gas derivative commodity instruments by approximately $100 million and $283 million, respectively. A hypothetical increase of 10% in the NYMEX natural gas price on December 31, 2025 and 2024 would decrease the fair value of our natural gas derivative commodity instruments by approximately $93 million and $340 million, respectively. For purposes of this analysis, we applied the 10% change in the NYMEX natural gas price on December 31, 2025 and 2024 to our natural gas derivative commodity instruments as of December 31, 2025 and 2024 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 and Eureka's revolving credit facilities. In addition, changes in Eureka's consolidated leverage ratio as a result of 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 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 and Eureka's revolving credit facility during 2025 would have increased interest expense attributable to EQT by approximately $3 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 do not fluctuate based on changes to the credit ratings assigned to EQT's 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 7 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 62%, or $159 million, of our OTC derivative contracts outstanding at December 31, 2025 had a positive fair value. Approximately 20%, or $93 million, of our OTC derivative contracts outstanding at December 31, 2024 had a positive fair value.

As of December 31, 2025, we were not in default under any derivative contracts and had no knowledge of default by any counterparty to our derivative contracts. During 2025, 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, 2025, no single lender in the syndicates for EQT's and Eureka's revolving credit facilities held more than 10% and 11%, respectively, of the financial commitments under each facility. The large syndicate group and relatively low percentage of participation by each lender are expected to limit our exposure to disruption or consolidation in the banking industry.

Item 8. Financial Statements and Supplementary Data

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, 2025 and 2024, the related statements of consolidated operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 18, 2026 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 (SEC) 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, 2025, the net book value of the Company's proved oil and natural gas properties was $20,785 million, and depreciation and depletion (DD&A) expense of the Company's Upstream segment was $2,263 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. Significant judgment is required by the Company's engineers in estimating proved natural gas, NGLs and oil reserves. Estimating reserves also requires the selection of inputs, including commodity 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, 2025.

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 independent 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 Natural Gas and Oil Properties

Description of the Matter	As described in Note 11 to the consolidated financial statements, on July 1, 2025, the Company completed the Olympus Energy Acquisition of certain natural gas and oil properties and related midstream assets. EQT accounted for the Olympus Energy Acquisition as a business combination under the acquisition method. The Company's accounting for the Olympus Energy Acquisition included determining the fair value of the acquired natural gas and oil properties. The determination of fair value of the acquired natural gas and oil properties included significant judgment and assumptions by management, including future commodity prices, anticipated production volumes, and a weighted average cost of capital (WACC). Auditing the Company's valuation of acquired natural gas and oil properties involved a high degree of subjectivity as the determination of fair value was based on assumptions as described above 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 Company's engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff, the independent engineers used to audit the estimates, and the external valuation advisors used to assist with the determination of the fair value of certain natural gas and oil properties. Our testing of the Company's estimate of fair value of the acquired natural gas and oil properties included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. The audit 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 (future commodity prices and WACC rates) used to develop the fair value estimate. We assessed the reasonableness of management's assumptions by comparing the significant market-related assumptions used in the cash flow model to external market and third-party data and anticipated production volumes to the reserve estimates audited by the independent engineers.

/s/ Ernst & Young LLP

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

Pittsburgh, Pennsylvania

February 18, 2026

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, 2025, 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, 2025, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related statements of consolidated operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2025, and the related notes and financial statement schedule listed in the Index at Item 15(a), and our report dated February 18, 2026 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 18, 2026

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

	2025	2024	2023
	(Thousands, except per share amounts)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	$ 7,726,712	$ 4,934,366	$ 5,044,768
Gain on derivatives	290,994	51,117	1,838,941
Pipeline and other	626,505	287,826	25,214
Total operating revenues	8,644,211	5,273,309	6,908,923
Operating expenses:			
Transportation and processing	1,532,090	1,915,616	2,157,260
Production	388,696	377,007	239,001
Operating and maintenance	225,131	110,393	15,699
Exploration	3,601	2,735	3,330
Selling, general and administrative	380,066	336,724	236,171
Depreciation, depletion and amortization	2,600,390	2,162,350	1,732,142
(Gain) loss on sale/exchange of long-lived assets	(31,214)	(764,044)	17,445
Impairment and expiration of leases	51,152	97,368	109,421
Other operating expenses	244,680	349,864	84,043
Total operating expenses	5,394,592	4,588,013	4,594,512
Operating income	3,249,619	685,296	2,314,411
Income from investments	(184,444)	(76,039)	(7,596)
Other income	(4,826)	(25,983)	(1,231)
Loss on debt extinguishment	22,652	68,299	80
Interest expense, net	438,695	454,825	219,660
Income before income taxes	2,977,542	264,194	2,103,498
Income tax expense	651,884	22,079	368,954
Net income	2,325,658	242,115	1,734,544
Less: Net income (loss) attributable to noncontrolling interests	286,411	11,538	(688)
Net income attributable to EQT Corporation	$ 2,039,247	$ 230,577	$ 1,735,232
Income per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	611,571	509,597	380,902
Net income attributable to EQT Corporation	$ 3.33	$ 0.45	$ 4.56
Diluted (Note 10):			
Weighted average common stock outstanding	615,717	514,593	413,224
Net income attributable to EQT Corporation	$ 3.31	$ 0.45	$ 4.22

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,

	2025	2024	2023
		(Thousands)	
Net income	$ 2,325,658	$ 242,115	$ 1,734,544
Other comprehensive income, net of tax:			
Other postretirement benefits liability adjustment, net of tax: $137, $252 and $59	148	363	310
Comprehensive income	2,325,806	242,478	1,734,854
Less: Comprehensive income (loss) attributable to noncontrolling interests	286,411	11,538	(688)
Comprehensive income attributable to EQT Corporation	$ 2,039,395	$ 230,940	$ 1,735,542

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

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2025	2024
	(Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 110,795	$ 202,093
Accounts receivable (less allowance for credit losses: $3,088 and $12,529)	1,457,959	1,132,608
Derivative instruments, at fair value	202,390	143,581
Income tax receivable	27,756	97,378
Prepaid expenses and other	96,251	139,019
Total current assets	1,895,151	1,714,679
Property, plant and equipment	48,472,497	44,505,504
Less: Accumulated depreciation and depletion	14,914,689	12,757,686
Net property, plant and equipment	33,557,808	31,747,818
Investments in unconsolidated entities	3,630,577	3,617,397
Net intangible assets	200,486	215,257
Goodwill	2,062,462	2,079,481
Other assets	446,390	455,623
Total assets	$ 41,792,874	$ 39,830,255
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt	$ 507,119	$ 320,800
Accounts payable	1,367,431	1,177,656
Derivative instruments, at fair value	137,299	446,519
Accrued interest	137,505	167,157
Other current liabilities	335,487	349,417
Total current liabilities	2,484,841	2,461,549
Revolving credit facility borrowings	360,000	150,000
Senior notes	6,933,209	8,853,377
Deferred income taxes	3,472,010	2,851,103
Asset retirement obligations and other liabilities	1,182,666	1,236,090
Total liabilities	14,432,726	15,552,119
Equity:		
Common stock, no par value, shares authorized: 1,280,000, shares issued: 624,076 and 596,870	19,517,761	18,014,711
Retained earnings	4,237,089	2,585,238
Accumulated other comprehensive loss	(2,173)	(2,321)
Total common shareholders' equity	23,752,677	20,597,628
Noncontrolling interest in consolidated subsidiaries	3,607,471	3,680,508
Total equity	27,360,148	24,278,136
Total liabilities and equity	$ 41,792,874	$ 39,830,255

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,

	2025	2024	2023
		(Thousands)	
Cash flows from operating activities:			
Net income	$ 2,325,658	$ 242,115	$ 1,734,544
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	657,836	14,732	384,666
Depreciation, depletion and amortization	2,600,390	2,162,350	1,732,142
(Gain) loss on sale/exchange of long-lived assets	(31,214)	(764,044)	17,445
Impairments	51,152	97,368	109,421
Income from investments	(184,444)	(76,039)	(7,596)
Loss on debt extinguishment	22,652	68,299	80
Share-based compensation expense	60,781	158,344	49,834
Distributions from equity method investments	257,233	66,200	18,693
Other	15,115	15,069	16,943
Gain on derivatives	(290,994)	(51,117)	(1,838,941)
Net cash settlements (paid) received on derivatives	(83,381)	1,217,895	900,650
Net premiums paid on derivatives	(44,752)	(42,394)	(322,663)
Changes in other assets and liabilities:			
Accounts receivable	(353,472)	(220,446)	867,679
Accounts payable	207,074	16,512	(406,113)
Income tax receivable and payable	73,028	(7,913)	(5,120)
Other current assets	45,191	(77,343)	98,907
Other items, net	(201,901)	7,385	(171,721)
Net cash provided by operating activities	5,125,952	2,826,973	3,178,850
Cash flows from investing activities:			
Capital expenditures	(2,288,425)	(2,253,709)	(2,019,037)
Cash paid for acquisitions, net of cash acquired	(483,522)	(874,265)	(2,271,881)
Net cash received for sale/exchange of assets	10,234	1,696,121	4,200
Capital contributions to equity method investments	(82,949)	(148,049)	(12,092)
Other investing activities	(245)	(80)	(14,845)
Net cash used in investing activities	(2,844,907)	(1,579,982)	(4,313,655)
Cash flows from financing activities:			
Proceeds from revolving credit facility borrowings	3,529,000	6,887,000	1,007,000
Repayment of revolving credit facility borrowings	(3,639,800)	(7,451,200)	(1,007,000)
Proceeds from issuance of debt	—	750,000	1,250,000
Proceeds from net settlement of Capped Call Transactions (Note 7)	—	93,290	—
Debt issuance costs	(9,623)	(18,854)	(5,336)
Repayment and retirement of debt	(1,401,623)	(4,313,867)	(1,015,836)
Net (premiums paid) discounts received on debt extinguishment	(39,311)	(52,432)	5,178
Dividends paid	(389,633)	(326,581)	(228,339)
Repurchase and retirement of common stock	—	—	(201,029)
Net proceeds from the sale of units of the Midstream Joint Venture (Note 9)	(1,135)	3,410,392	—
Net distributions to noncontrolling interest	(359,696)	(1,640)	(7,322)
Cash paid for taxes to net settle share-based incentive awards	(54,175)	(102,872)	(41,780)
Other financing activities	(6,347)	889	1,602
Net cash used in financing activities	(2,372,343)	(1,125,875)	(242,862)
Net change in cash and cash equivalents	(91,298)	121,116	(1,377,667)
Cash and cash equivalents at beginning of year	202,093	80,977	1,458,644
Cash and cash equivalents at end of year	$ 110,795	$ 202,093	$ 80,977

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, 2025, 2024 AND 2023

	Common Stock					
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Loss (a)	Noncontrolling Interest in Consolidated Subsidiaries	Total Equity
			(Thousands, except per share amounts)			
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 (Note 7)	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 11)	49,600	2,152,631				2,152,631
Distributions to noncontrolling interest					(11,072)	(11,072)
Contributions 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 (Note 7)	19,992	285,608				285,608
Net settlement of Capped Call Transactions (Note 7)		93,290				93,290
Equitrans Midstream Merger (Note 11)	152,428	5,548,608			162,993	5,711,601
Change in ownership of consolidated subsidiary, net (Note 9)		(77,469)			3,500,000	3,422,531
Distributions 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
Comprehensive income, net of tax:						
Net income			2,039,247		286,411	2,325,658
Other postretirement benefits liability adjustment, net of tax: $137				148		148
Dividends ($0.6375 per share)			(387,396)			(387,396)
Share-based compensation plans	1,977	26,863				26,863
Olympus Energy Acquisition (Note 11)	25,229	1,471,365				1,471,365
Equitrans Midstream Merger (Note 11)					248	248
Change in ownership of consolidated subsidiary, net (Note 9)		4,822				4,822
Distributions to noncontrolling interest					(359,696)	(359,696)
Balance at December 31, 2025	624,076	$19,517,761	$ 4,237,089	$ (2,173)	$ 3,607,471	$ 27,360,148

For all periods presented, there were 3 million preferred shares authorized and 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, 2025

1. Summary of Significant Accounting Policies

Nature of Operations. EQT Corporation is an integrated natural gas company with upstream, 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 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 owns 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.

The Company consolidates its controlling interest in the Midstream Joint Venture (defined in Note 9) under the voting interest entity model. See Note 9 for discussion of the method of allocation used in accounting for the portion of Midstream Joint Venture that is not owned by the Company.

In addition, the Company consolidates its 60% interest in Eureka Midstream Holdings, LLC (Eureka 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. Eureka Holdings conducts its operations through its wholly owned subsidiary, Eureka Midstream, LLC (Eureka), which has a revolving credit facility that is consolidated into the Company's debt. See Note 7.

In 2023, a variable interest entity formed in 2020 and previously consolidated by the Company was dissolved following a pro rata distribution of its assets to its members. The Company had previously consolidated the entity as the Company was its primary beneficiary.

Prior to the NEPA Gathering System Acquisition (defined in Note 11) and the First NEPA Non-Operated Asset Divestiture (defined in Note 12), the Company recorded its pro rata share of the NEPA Gathering System (defined in Note 11) in the Consolidated Financial Statements. Following these transactions, the Company owns 100% of the NEPA Gathering System.

Segments. The Company has three reportable segments reflecting its three lines of business consisting of Upstream, 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, effective as of December 31, 2025, the Company renamed its previously reported "Production" segment as the "Upstream" segment.

Use of Estimates. The preparation of the Consolidated 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 in the Statements of Consolidated Operations.

Accounts Receivable, Net of Allowance for Credit Losses. The Company's accounts receivable relate primarily to sales of natural gas and natural gas liquids (NGLs), pipeline revenue and amounts due from joint interest partners. See Note 3 for a discussion of amounts due from contracts with customers. Allowances for credit losses are recorded in selling, general and administrative expense in the Statements of Consolidated Operations. Judgment is required in assessing the ultimate realization of the Company's accounts receivable. The allowance for credit losses is 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,	
	2025	**2024**
	(Thousands)	
Margin requirements with counterparties (see Note 4)	$ 36,810	$ 86,975
Prepaid expenses and other current assets	59,441	52,044
Total prepaid expenses and other	$ 96,251	$ 139,019

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

	December 31,	
	2025	**2024**
	(Thousands)	
Oil and gas producing properties	$ 36,785,910	$ 33,549,913
Less: Accumulated depletion	14,344,974	12,489,317
Net oil and gas producing properties	22,440,936	21,060,596
Other upstream assets, at cost less accumulated depreciation	27,073	20,434
Net upstream assets	22,468,009	21,081,030
Gathering assets	8,677,011	8,067,556
Less: Accumulated depreciation	337,889	131,546
Net gathering assets	8,339,122	7,936,010
Transmission and storage assets	2,751,815	2,667,352
Less: Accumulated depreciation	110,539	30,027
Net transmission and storage assets	2,641,276	2,637,325
Other property, plant and equipment, at cost less accumulated depreciation	109,401	93,453
Net property, plant and equipment	$ 33,557,808	$ 31,747,818

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 2025, 2024 and 2023, the Company capitalized internal costs of approximately $82 million, $69 million and $57 million, respectively, to its oil and gas producing properties. In addition, in 2025, 2024 and 2023, the Company capitalized interest related to well development of approximately $32 million, $54 million and $41 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 $0.95, $0.90 and $0.84 per Mcfe for the years ended December 31, 2025, 2024 and 2023, respectively.

There were no exploratory wells drilled during 2025, 2024 and 2023, and there were no capitalized exploratory well costs for the years ended December 31, 2025, 2024 and 2023.

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 2025 and 2024, the Company capitalized internal costs of approximately $35 million and $25 million, respectively, to its gathering assets and $15 million and $4 million, respectively, to its transmission and storage assets. In addition, in 2025 and 2024, the Company capitalized interest of approximately $8 million and $3 million, respectively, related to its gathering assets.

The Company's gathering, transmission and storage assets are depreciated on a straight-line basis using composite rates over their estimated useful lives. These assets had an average depreciation rate of 2.8% and 3.1% for the years ended December 31, 2025 and 2024, respectively. Depreciation rates for regulated transmission and storage assets are subject to review in connection with filings made with the Federal Energy Regulatory Commission (the FERC).

Impairment of Property, Plant and Equipment

Impairment of Proved Oil and Gas Properties and Related Midstream Assets. The carrying values of the Company's proved oil and gas properties, together with related midstream assets that are operationally and economically interdependent, are reviewed for impairment when events or circumstances indicate that the carrying amount 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 Company's internal planning assumptions, including, among other things, future natural gas and NGLs sales prices; estimated reserve quantities and expected timing of production; projected gathered and processed volumes and transmission throughput; associated fee-based revenues; future operating costs and capital requirements; and discount and inflation assumptions. 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. No indicators of impairment to the Company's material asset groups were identified during 2025, 2024 and 2023.

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, historical experience or changes in market conditions. 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, 2025, 2024 and 2023, the Company recorded $51.2 million, $97.4 million and $109.4 million, respectively, for impairment and expiration of leases. The Company's unproved properties had a net book value of approximately $1,656 million and $1,563 million as of December 31, 2025 and 2024, respectively.

Impairment of Other Property, Plant and Equipment. The Company evaluates its other property, plant and equipment for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. No indicators of impairment were identified during 2025, 2024 and 2023.

Investments in Unconsolidated Entities. The Company applies the equity method of accounting to its investments in entities over which 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. The Company's pro-rata share of income or loss from these investments is recorded in income from investments in the Statements of Consolidated Operations.

The Company accounts for investments in entities over which the Company does not have the ability to exercise significant influence as investments in equity securities. Changes in the fair value of these investments are recorded in income from investments, and dividends received on such investments are recorded in other income in the Statements of Consolidated Operations.

See Note 8 for a discussion of the Company's investments in unconsolidated entities.

The Company evaluates its investments in unconsolidated entities for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. The Company considers expected future cash flows of the investee, the investee's ability to generate cash flows sufficient to recover its carrying value, and market, operational or financial developments. The recognition of an impairment loss is required if the impairment is considered other than temporary. No indicators of impairment to the Company's investments in unconsolidated entities were identified during 2025, 2024 and 2023.

Net Intangible Assets. The following table summarizes the Company's intangible assets.

	December 31,	
	2025	2024
	(Thousands)	
Acquired transmission services agreements	$ 200,000	$ 200,000
Less: Accumulated amortization	19,234	5,901
Net intangible assets related to acquired transmission services agreements	180,766	194,099
Other intangible assets	24,922	24,922
Less: Accumulated amortization	5,202	3,764
Net other intangible assets	19,720	21,158
Net intangible assets	$ 200,486	$ 215,257

The intangible assets related to acquired transmission services agreements are amortized on a straight-line basis over their estimated useful lives, which reflects the pattern in which the Company expects to consume the economic benefits of the assets. During the years ended December 31, 2025 and 2024, the Company recognized amortization expense of $13.3 million and $5.9 million, respectively, related to these acquired transmission services agreement intangible assets. The estimated annual amortization expense for these intangible assets is $13.3 million for each of the next 5 years.

The Company evaluates its intangible assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. Indicators of potential impairment may include changes in market conditions, customer demand or expected utilization of the underlying contracts. No indicators of impairment to the Company's net intangible assets were identified during 2025 and 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 (including, among other things, the Company's market capitalization and stock price as well as relevant market, economic or regulatory developments) to determine whether it is more likely than not (greater than 50%) that the fair value of the Company's 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 that incorporates forecasted cash flows, discount rate assumptions including weighted-average cost of capital, terminal growth rates and relevant industry multiples. 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, 2025 and determined there were no indicators of impairment. Changes in goodwill during the year ended December 31, 2025 reflect measurement-period adjustments resulting from the finalization of the purchase price allocation for the Equitrans Midstream Merger (defined in Note 11).

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

	December 31, 2025	December 31, 2024
	(Thousands)	
Accrued taxes other than income	$ 108,626	$ 114,700
Accrued incentive compensation	90,694	53,138
Current portion of lease liabilities	58,124	41,878
Current portion of long-term capacity contracts	30,903	43,697
Accrued payroll	9,313	12,115
Deferred revenue	6,240	24,187
Other accrued liabilities	31,587	59,702
Total other current liabilities	$ 335,487	$ 349,417

Unamortized Debt Discounts and Issuance Costs. Discounts and costs incurred with the issuance of debt are capitalized as a reduction of debt and amortized into net interest expense over the term of the debt. Costs incurred with the issuance or amendment of revolving credit facilities are capitalized as a noncurrent asset and amortized into net interest expense over the term of the facility. See Note 7.

Leases. See Note 15 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 income. 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.

The Midstream Joint Venture and Eureka Holdings 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. The Midstream Joint Venture's and Eureka Holdings' 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 the Midstream Joint Venture and Eureka Holdings, 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 federal and state taxable income forecasts, state apportionment analyses, reversals of temporary differences, tax planning strategies, prior year carrybacks and the expected utilization of tax credits.

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 6.

Insurance. The Company maintains insurance coverage for customary insurable risks, including general liability, workers' compensation, auto liability, environmental liability, property damage, business interruption, fiduciary liability and directors' and officers' liability. These policies are subject to deductibles, self-insured retentions, 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 maintains insurance coverage for such losses arising on or after November 12, 2020.

Certain legacy insurance programs of Equitrans Midstream Corporation (Equitrans Midstream), which the Company acquired in July 2024 (see Note 11), applied to losses arising prior to the transition to the Company's insurance programs. These programs included higher self-insured retentions for certain material losses related to excess liability and environmental liability arising before December 20, 2024 as well as limited co-insurance related to material losses under the property insurance coverage. Losses arising thereafter are included in the Company's insurance programs, which generally do not include high self-insured retentions or co-insurance amounts.

The Company records insurance reserves on an undiscounted basis using analyses of historical claims 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. While the Company believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims, differ from estimates. There can be no assurance that the insurance policies we maintain to limit our liability for such losses will be adequate to protect the Company 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.

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 of the obligation are based on the expected timing of settlement, estimated costs (informed by the Company's historical experience with plugging and abandoning wells and reclaiming or disposing of other assets), the estimated remaining lives of the wells and related assets and the discount rates used to determine the present value of expected future settlement costs.

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 asset retirement obligations and other liabilities in the Consolidated Balance Sheets.

	December 31,	
	2025	2024
	(Thousands)	
Balance at January 1	$ 1,003,570	$ 911,057
Accretion expense	76,745	68,501
Liabilities incurred	31,394	21,587
Liabilities settled	(52,210)	(66,729)
Liabilities assumed in acquisitions	14,923	45,847
Liabilities removed in divestitures (a)	(98,839)	(28,701)
Change in estimates (b)	43,922	52,008
Balance at December 31	$ 1,019,505	$ 1,003,570

(a) Primarily attributable to the derecognition of asset retirement obligations associated with the Non-Core Asset Divestiture (defined and discussed in Note 12).
(b) During 2025 and 2024, the Company recorded changes in estimates attributable primarily to increased 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. Equitrans, L.P., a non-wholly owned subsidiary of the Company, owns and operates FERC-regulated transmission and storage assets.

Rate regulation established the rates Equitrans, L.P. may charge for regulated services and provides for the recovery of costs plus an authorized return on invested capital. Regulatory accounting permits the deferral of certain costs and income as regulated assets and liabilities when it is probable that such amounts will be recovered from, or refunded to, customers through future rates. These deferred amounts are recognized in the Statements 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 Statements of Operations. The Company did not have regulated operations during the year ended December 31, 2023.

	Years Ended December 31,	
	2025	2024
	(Thousands)	
Operating revenues	$ 572,975	$ 218,569
Operating expenses	194,576	78,908

The following table presents Equitrans, L.P.'s regulated property, plant and equipment included in the Company's Consolidated Balance Sheets.

	December 31,	
	2025	2024
	(Thousands)	
Property, plant and equipment	$ 2,751,815	$ 2,667,352
Less: Accumulated depreciation	110,539	30,027
Net property, plant and equipment	$ 2,641,276	$ 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 asset retirement obligations and other liabilities. The following table summarizes Equitrans, L.P.'s regulated assets and liabilities.

	December 31, 2025	December 31, 2024
	(Thousands)	
Regulated assets:		
Deferred taxes (a)	$ 139,221	$ 142,757
Other recoverable costs (b)	17,938	23,182
Total regulated assets	$ 157,159	$ 165,939
Regulated liabilities:		
Deferred taxes (a)	$ 8,136	$ 8,534
Ongoing postretirement benefits other than pension and other reimbursable costs (c)	23,199	20,158
Total regulated liabilities	$ 31,335	$ 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 8.5 years, and costs associated with a legacy postretirement benefits plan, which Equitrans, L.P. expects to continue to recover over the next 6.5 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 other revenues.

Share-based Compensation. See Note 14 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, 2025	2024	2023
	(Thousands)		
Changes in legal and environmental reserves, including settlements	$ 185,253	$ 16,271	$ 9,342
Transaction costs	35,843	309,419	56,263
Other	23,584	24,174	18,438
Total other operating expenses	$ 244,680	$ 349,864	$ 84,043

Defined Contribution Plan. The Company recognized expense related to its defined contribution plan of $25.1 million, $14.5 million and $9.0 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Income Per Share. See Note 10 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,		
	2025	2024	2023
		(Thousands)	
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$ 455,091	$ 401,768	$ 213,141
Income taxes, net	(79,022)	7,960	13,350
Non-cash activity during the period for:			
Issuance of EQT common stock as consideration for acquisition (Note 11)	$ 1,471,365	$ 5,548,608	$ 2,152,631
Increase in asset retirement costs and obligations	75,390	73,576	106,548
Increase in right-of-use assets and lease liabilities, net	65,323	29,568	45,774
Capitalization of non-cash equity share-based compensation	20,258	10,095	6,287
Investments in unconsolidated entities	17,981	3,428	—
Issuance of EQT common stock upon Convertible Notes settlement (Note 7)	—	285,608	122,830
First NEPA Non-Operated Asset Divestiture (Note 12)	—	155,318	—
Accrued transaction costs related to the sale of units of the Midstream Joint Venture (Note 9)	—	1,135	—
Dissolution of consolidated variable interest entity	—	—	25,227

Recently Issued Accounting Standards

In December 2025, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2025-12, *Codification Improvements*, to clarify guidance, correct technical errors, remove outdated language and improve consistency across various topics in the Accounting Standards Codification. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2026, including interim reporting periods within those annual periods. Early adoption is permitted. The Company is evaluating the impact ASU 2025-12 will have on its financial statements and related disclosures and does not expect adoption of ASU 2025-12 to have a material impact.

In December 2025, the FASB issued ASU 2025-11, *Interim Reporting (Topic 270): Narrow-Scope Improvements*, to clarify the scope and presentation requirements for interim GAAP financial statements and to consolidate interim disclosure requirements. Under this ASU, entities must disclose material events or changes occurring after year end that affect interim periods. The amendments in this ASU are effective for interim reporting periods within annual reporting periods beginning after December 15, 2027. Early adoption is permitted. The amendments may be applied either prospectively or retrospectively to any or all prior periods presented in the financial statements. The Company is evaluating the impact ASU 2025-11 will have 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.

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 (i) disclose specific categories in the rate reconciliation and (ii) provide additional information for reconciling items that meet a quantitative threshold. This ASU is effective for annual reporting periods beginning after December 15, 2024. The Company adopted ASU 2023-09 in the fourth quarter of 2025. See Note 6 for related disclosures.

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

2. Financial Information by Business Segment

The Company has three reportable segments consisting of Upstream, Gathering and Transmission.

Effective as of December 31, 2025, the Company renamed its previously reported "Production" segment as the "Upstream" segment to better align with the nature of the Company's operations and the Company's internal reporting framework. This change had no impact on the structure of the Company's internal organization, including the composition of its reportable segments.

The Company's Upstream segment comprises the Company's natural gas, natural gas liquids (NGLs) and oil extraction, development and production business and supporting operations. The Company's Gathering segment owns and operates the Company's gathering system, which has extensive overlap with the Company's Upstream 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 Company's investment in the MVP Joint Venture (defined in Note 8) is reported in its Transmission segment.

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

Items that are managed on a consolidated basis, including cash and cash equivalents, debt, income taxes and amounts related to the Company's corporate function, and items related to the Company's energy transition initiatives have not been allocated to the Company's reportable segments and have been presented as "Other."

The Company's chief operating decision maker (the CODM), Toby Rice, President and Chief Executive Officer, evaluates performance of, and allocates resources to, the Company's reportable segments using a profitability metric of operating income. The CODM compares each segment's operating income and return on assets when evaluating performance of the Company's reportable segments and considers actual-to-forecast variances in operating income when allocating capital and personnel to the Company's reportable segments. For the Company's Transmission segment, the CODM also reviews equity earnings recognized from, and the carrying value of, the Company's investment in the MVP Joint Venture.

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

Total segment operating income. The following tables present information about segment revenue, segment profit or loss and significant segment expenses and include a reconciliation of total segment amounts to the Company's consolidated totals.

	Year Ended December 31, 2025					
	Upstream	**Gathering**	**Transmission**	**Total Segment**	**Intersegment Eliminations and Other**	**EQT Corporation**
	(Thousands)					
Operating revenues:						
Sales of natural gas, natural gas liquids and oil	$ 7,726,712	$ —	$ —	$ 7,726,712	$ —	$ 7,726,712
Gain on derivatives	290,994	—	—	290,994	—	290,994
Pipeline and other	6,351	1,301,434	572,252	1,880,037	(1,253,532)	626,505
Total operating revenues	8,024,057	1,301,434	572,252	9,897,743	(1,253,532)	8,644,211
Operating expenses (a):						
Transportation and processing	2,783,455	—	—	2,783,455	(1,251,365)	1,532,090
Production	388,696	—	—	388,696	—	388,696
Operating and maintenance	—	166,990	58,141	225,131	—	225,131
Exploration	3,601	—	—	3,601	—	3,601
Selling, general and administrative	217,803	66,642	37,339	321,784	58,282	380,066
Depreciation, depletion and amortization	2,263,105	212,353	101,718	2,577,176	23,214	2,600,390
(Gain) loss on sale/ exchange of long-lived assets	(31,513)	(29)	349	(31,193)	(21)	(31,214)
Impairment and expiration of leases	50,341	811	—	51,152	—	51,152
Other operating expenses (b)	30,438	18,013	(527)	47,924	196,756	244,680
Total operating expenses	5,705,926	464,780	197,020	6,367,726	(973,134)	5,394,592
Operating income (loss)	$ 2,318,131	$ 836,654	$ 375,232	$ 3,530,017	$ (280,398)	$ 3,249,619

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

(b) Corporate other operating expenses consisted primarily of legal reserves related to the Securities Class Action (defined in Note 13) and transaction costs related to the Olympus Energy Acquisition (defined in Note 11). See Notes 13 and 11 for information on the Securities Class Action and Olympus Energy Acquisition, respectively. See Note 1 for a summary of the Company's consolidated other operating expenses.

	Year Ended December 31, 2024					
	Upstream	**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 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 CODM.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast for the Company's change in reportable segments from one reportable segment to three reportable segments as the necessary information was 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 11. See Note 1 for a summary of the Company's consolidated other operating expenses.

	Year Ended December 31, 2023				
	Upstream	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 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 CODM.

(b) Selling, general and administrative expense incurred prior to the Equitrans Midstream Merger closing date was not recast for the Company's change in reportable segments from one reportable segment to three reportable segments as the necessary information was 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 11). See Note 1 for a summary of the Company's consolidated other operating expenses.

Reconciliation of total segment operating income to consolidated income before income taxes

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Total segment operating income	$ 3,530,017	$ 1,075,902	$ 2,399,042
Less:			
Intersegment eliminations	2,303	457	—
Unallocated amounts:			
Unallocated other revenues	(136)	(34)	—
Corporate selling, general and administrative	58,282	36,254	—
Corporate depreciation and amortization	23,214	16,761	9,765
Corporate gain on sale/exchange of long-lived assets	(21)	—	—
Corporate other operating expenses (a)	196,756	337,168	74,866
Income from investments (b)	(184,444)	(76,039)	(7,596)
Other income	(4,826)	(25,983)	(1,231)
Loss on debt extinguishment	22,652	68,299	80
Interest expense, net	438,695	454,825	219,660
Income before income taxes	$ 2,977,542	$ 264,194	$ 2,103,498

(a) For the year ended December 31, 2025, corporate other operating expenses consisted primarily of legal reserves related to the Securities Class Action and transaction costs related to the Olympus Energy Acquisition. For the year ended December 31, 2024, corporate other operating expenses consisted primarily of transaction costs related to the Equitrans Midstream Merger. For the year ended December 31, 2023, corporate other operating expenses consisted primarily of transaction costs related to the Tug Hill and XcL Midstream Acquisition.

(b) For the years ended December 31, 2025 and 2024, income from investments included $154.3 million and $78.8 million, respectively, of equity earnings from the Company's investment in the MVP Joint Venture.

Total segment assets. The following table presents information about segment assets. The Company's investment in the MVP Joint Venture is presented in investments in unconsolidated entities in the Consolidated Balance Sheets.

	Upstream	Gathering	Transmission	Total Segment
December 31, 2025	(Thousands)			
Investment in the MVP Joint Venture	$ —	$ —	$ 3,514,803	$ 3,514,803
Goodwill (a)	—	—	1,231,783	1,231,783
Other segment assets	24,295,091	8,676,118	2,891,096	35,862,305
Total assets	$ 24,295,091	$ 8,676,118	$ 7,637,682	$ 40,608,891
December 31, 2024				
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

(a) Changes in goodwill during the year ended December 31, 2025 reflect measurement-period adjustments resulting from the finalization of the purchase price allocation for the Equitrans Midstream Merger.

Reconciliation of total segment assets to consolidated total assets

	December 31,		
	2025	2024	2023
		(Thousands)	
Total segment assets	$ 40,608,891	$ 38,513,727	$ 25,019,540
Intersegment eliminations	(204,403)	(318,835)	(47,471)
Unallocated amounts:			
Cash and cash equivalents	110,795	202,093	80,977
Income tax receivable	27,756	97,378	91,414
Other property, plant and equipment, at cost less accumulated depreciation	109,401	93,453	40,739
Goodwill (a)	830,679	861,739	—
Regulatory asset from deferred taxes	139,221	142,757	—
Other	170,534	237,943	99,899
Total assets	$ 41,792,874	$ 39,830,255	$ 25,285,098

(a) Represents unallocated goodwill attributable to additional deferred tax liabilities recognized in connection with the Equitrans Midstream Merger. Changes in goodwill during the year ended December 31, 2025 reflect measurement-period adjustments resulting from the finalization of the purchase price allocation for the Equitrans Midstream Merger.

Total segment capital expenditures. The following table presents information about segment capital expenditures.

	Years Ended December 31,		
	2025	2024	2023
		(Thousands)	
Upstream	$ 1,878,052	$ 2,003,635	$ 1,878,417
Gathering	367,697	202,264	31,701
Transmission	51,769	31,446	—
Total segment capital expenditures	2,297,518	2,237,345	1,910,118
Other corporate items	26,119	28,603	15,125
Total capital expenditures	$ 2,323,637	$ 2,265,948	$ 1,925,243

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 fee 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 because 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 and other revenues in the Statements of Consolidated Operations. Derivative contracts are also outside the scope of ASU 2014-09.

	Years Ended December 31,		
	2025	2024	2023
		(Thousands)	
Revenues from contracts with customers:			
Upstream sales			
Natural gas	$ 7,018,766	$ 4,224,882	$ 4,520,817
NGLs	620,384	615,933	427,760
Oil	87,562	93,551	96,191
Sales of natural gas, NGLs and oil	7,726,712	4,934,366	5,044,768
Gathering pipeline revenue			
Firm reservation fee (a)	632,916	313,987	—
Volumetric-based fee	668,518	452,476	161,395
Total Gathering pipeline revenue	1,301,434	766,463	161,395
Transmission pipeline revenue			
Firm reservation fee	435,194	183,088	—
Volumetric-based fee	137,058	35,205	—
Total Transmission pipeline revenue	572,252	218,293	—
Intersegment eliminations and other	(1,253,532)	(704,517)	(148,830)
Total revenues from contracts with customers (b)	8,346,866	5,214,605	5,057,333
Other sources of revenue:			
Gain on derivatives	290,994	51,117	1,838,941
Other revenues	6,351	7,587	12,649
Total other sources of revenue	297,345	58,704	1,851,590
Total operating revenues	$ 8,644,211	$ 5,273,309	$ 6,908,923

(a) Firm reservation fee revenue included unbilled revenues supported by MVCs of $18.4 million and $4.2 million for the years ended December 31, 2025 and 2024, respectively.

(b) For contracts with customers in which the Company had satisfied its performance obligations and held an unconditional right to consideration at the balance sheet date, the Company recorded accounts receivable of $1,159.0 million and $939.9 million as of December 31, 2025 and 2024, 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, 2025. The table excludes contracts that qualified for the exception to the relative standalone selling price method as of December 31, 2025.

	2026	2027	2028	2029	2030	Thereafter	Total
				(Thousands)			
Upstream natural gas sales	$ 4,597	$ 1,978	$ —	$ —	$ —	$ —	$ 6,575
Gathering firm reservation fee revenue:							
Third-party	100,794	85,998	85,998	85,998	85,998	287,261	732,047
Affiliate	101,792	101,450	97,701	97,701	103,977	1,403,698	1,906,319
Total	202,586	187,448	183,699	183,699	189,975	1,690,959	2,638,366
Gathering revenue supported by MVCs:							
Third-party	96,377	89,203	80,536	67,311	56,762	132,254	522,443
Affiliate	397,966	410,621	411,740	410,622	408,322	1,634,128	3,673,399
Total	494,343	499,824	492,276	477,933	465,084	1,766,382	4,195,842
Transmission firm reservation fee revenue:							
Third-party	185,328	176,986	171,814	169,198	165,686	660,199	1,529,211
Affiliate	253,089	262,637	260,776	260,445	260,445	1,704,604	3,001,996
Total	438,417	439,623	432,590	429,643	426,131	2,364,803	4,531,207
Total remaining performance obligations	$ 1,139,943	$ 1,128,873	$ 1,108,565	$ 1,091,275	$ 1,081,190	$ 5,822,144	$11,371,990

As of December 31, 2025, based on total projected contractual revenues, the Company's firm gathering contracts had weighted average remaining terms of approximately 10 years for third-party contracts and 13 years for affiliate contracts.

As of December 31, 2025, based on total projected contractual revenues, the Company's firm transmission and storage contracts had weighted average remaining terms of approximately 10 years for third-party contracts and 13 years for affiliate contracts.

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 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. See Note 5 for a description of the fair value hierarchy and the valuation techniques and significant inputs used to estimate the fair value of the Company's derivative instruments.

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 945 billion cubic feet (Bcf) of natural gas and 4,022 thousand barrels (Mbbl) of NGLs as of December 31, 2025, and approximately 2,189 Bcf of natural gas and 2,562 Mbbl of NGLs as of December 31, 2024. The open positions at December 31, 2025 and 2024 had maturities extending through December 2030 and December 2027, respectively.

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, 2025, 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, 2025 and 2024, the aggregate fair value of the Company's OTC derivative instruments with credit rating risk-related contingent features in a net liability position was $4.4 million and $61.9 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, 2025 and 2024, 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, 2025 and 2024, there was $36.8 million and $87.0 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, 2025		(Thousands)		
Asset derivative instruments, at fair value	$ 202,390	$ (79,250)	$ —	$ 123,140
Liability derivative instruments, at fair value	137,299	(79,250)	(36,810)	21,239
December 31, 2024				
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

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 and, when not available, valuation models that incorporate market-based inputs, including forward price curves, discount rates, volatilities and counterparty non-performance risk. 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, 2025		(Thousands)		
Asset derivative instruments, at fair value	$ 202,390	$ 43,200	$ 159,190	$ —
Liability derivative instruments, at fair value	137,299	39,164	98,135	—
December 31, 2024				
Asset derivative instruments, at fair value	$ 143,581	$ 50,300	$ 93,281	$ —
Liability derivative instruments, at fair value	446,519	81,074	365,445	—

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 and Eureka's revolving credit facilities 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, 2025 and 2024, the Company's senior notes had a fair value of approximately $7.7 billion and $8.8 billion, respectively, and a carrying value of approximately $7.4 billion and $8.9 billion, respectively, inclusive of any current portion. See Note 7 for further discussion of the Company's debt.

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

See Note 1 for a discussion of the fair value measurement and impairment assessments of the Company's property, plant and equipment, investments in unconsolidated entities, net intangible assets, goodwill and asset retirement obligations. See Note 8 for a discussion of the fair value measurement of the Company's investment in the Investment Fund (defined in Note 8). See Note 11 for a discussion of the fair value measurement of the assets acquired in the Olympus Energy Acquisition.

6. Income Taxes

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

	Years Ended December 31,		
	2025	2024	2023
		(Thousands)	
Current:			
Federal	$ (7,296)	$ 1,222	$ (10,894)
State	1,344	6,125	(4,818)
Current income tax (benefit) expense	(5,952)	7,347	(15,712)
Deferred:			
Federal	551,000	(21,463)	450,091
State	106,836	36,195	(65,425)
Deferred income tax expense	657,836	14,732	384,666
Total income tax expense	$ 651,884	$ 22,079	$ 368,954

For the year ended December 31, 2025, current income tax benefit is primarily composed of a reduction in prior year income tax liabilities and interest. 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.

On July 4, 2025, President Trump signed the One Big Beautiful Bill Act (the OBBBA) into law. Significant provisions affecting the Company include (i) the reinstatement of 100% bonus depreciation for qualifying property, (ii) the allowance for immediate and full expensing of domestic research and experimentation expenditures and (iii) the use of earnings before interest, taxes, depreciation and amortization, or EBITDA, rather than earnings before interest and taxes, or EBIT, in determining adjusted taxable income for purposes of any interest deduction limitation. The enactment of the OBBBA did not have a material impact on the Company's effective tax rate for the year ended December 31, 2025.

The table below summarizes income tax payments, net of refunds.

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Federal	$ (81,195)	$ 12,149	$ 12,876
State:			
Mississippi	*	*	670
Pennsylvania	*	(4,114)	*
Other U.S. states	2,173	(75)	(196)
Total taxes paid, net of refunds	$ (79,022)	$ 7,960	$ 13,350

*Indicates that the amount paid or refunded did not exceed the applicable disclosure threshold for the periods presented and is included in other U.S. states.

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,					
	2025		2024		2023	
	Amount	Rate	Amount	Rate	Amount	Rate
	(Thousands)		(Thousands)		(Thousands)	
Income before income taxes	$ 2,977,542		$ 264,194		$ 2,103,498	
U.S. federal statutory tax rate	$ 625,284	21.0 %	$ 55,481	21.0 %	$ 441,735	21.0 %
State and local income taxes, net of federal benefit (a)	95,217	3.2 %	35,115	13.3 %	(55,993)	(2.7)%
Tax credits:						
Research and development credits	(181)	— %	(5,779)	(2.2)%	(4,896)	(0.2)%
Other	(536)	— %	(758)	(0.3)%	180	— %
Changes in valuation allowances:						
Capital loss carryforward	—	— %	(52,820)	(20.0)%	78	— %
Other	977	— %	818	0.3 %	1,301	0.1 %
Nontaxable or nondeductible items:						
Transaction costs	—	— %	6,041	2.3 %	—	— %
Other	1,814	0.1 %	2,639	1.0 %	(2,984)	(0.1)%
Changes in unrecognized tax benefits (b)	(9,636)	(0.3)%	(16,977)	(6.4)%	(7,015)	(0.3)%
Other adjustments:						
Noncontrolling interests in consolidated subsidiaries	(60,156)	(2.0)%	(2,724)	(1.0)%	(334)	— %
Other	(899)	— %	1,043	0.4 %	(3,118)	(0.1)%
Total income tax expense and effective tax rate	$ 651,884	21.9 %	$ 22,079	8.4 %	$ 368,954	17.5 %

(a) The majority of the net state and local income tax effect relates to state income taxes in Pennsylvania and West Virginia for all periods presented.
(b) Changes in unrecognized tax benefits are presented on an aggregated basis for all jurisdictions.

The Company's effective tax rate for the year ended December 31, 2025 was higher compared to the U.S. federal statutory rate primarily as a result of state taxes net of valuation allowances, partly offset by the Midstream Joint Venture's and Eureka Holdings' income attributable to the noncontrolling interests.

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

	December 31,	
	2025	**2024**
	(Thousands)	
Deferred tax asset:		
NOL carryforwards	$ 789,888	$ 708,518
Federal tax credits	98,813	89,644
Interest disallowance limitation	45,222	106,622
Incentive compensation and deferred compensation plans	26,432	18,032
State capital loss carryforward	22,062	44,496
Net unrealized losses	—	80,723
Other	—	2,433
Deferred tax asset	982,417	1,050,468
Valuation allowance	(254,460)	(257,218)
Net deferred tax asset	727,957	793,250
Deferred tax liability:		
Property, plant and equipment	(2,792,495)	(2,516,074)
Investment in partnerships	(1,392,717)	(1,128,279)
Net unrealized gains	(13,070)	—
Other	(1,685)	—
Deferred tax liability	(4,199,967)	(3,644,353)
Net deferred tax liability	$ (3,472,010)	$ (2,851,103)

During 2025, the net deferred tax liability increased by $620.9 million compared to 2024 due primarily to temporary differences created by 100% bonus depreciation enacted with the OBBBA and the incremental accelerated deductions from the Olympus Energy Acquisition.

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

	December 31,	
	2025	2024
	(Thousands)	
NOL carryforwards:		
Federal (expires between 2032 and 2037)	$ 14,644	$ 14,644
Federal (indefinite expiration)	386,846	322,258
State (expires between 2026 and 2045)	354,822	347,279
State (indefinite expiration)	33,576	24,337
Total NOL carryforwards	$ 789,888	$ 708,518
Valuation allowance on NOL carryforwards:		
Federal	$ (13,870)	$ (14,263)
State	(202,472)	(187,321)
Total valuation allowance on NOL carryforwards	$ (216,342)	$ (201,584)

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 judgment 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 2025 and 2024, positive evidence considered included forecasts of future taxable income, the reversals of financial-to-tax temporary differences and the implementation of tax planning strategies. 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 (not included in the NOL table above) is related primarily to state limitations on interest expense under Internal Revenue Code Section 163(j) and state capital loss carryforwards generated from the sales of the Company's equity investment in Equitrans Midstream between February 2020 and April 2022. Capital losses may be utilized only to offset capital gains and are generally subject to a three-year carryback and five year carryforward period for potential 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, 2025, the Company had a valuation allowance related to the interest expense limitation of $10.5 million and the capital loss carryforward of $22.1 million for state income tax purposes due to the limitations on future potential utilization. As of December 31, 2024, the Company had a valuation allowance related to the interest expense limitation of $10.4 million and the capital loss carryforward of $44.5 million for state income tax purposes due to the limitations on future potential utilization. The reduction of the valuation allowance during 2025 primarily reflects the expiration of a portion of the capital loss carryforward.

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

	2025	2024	2023
		(Thousands)	
Balance at January 1	$ 72,743	$ 89,197	$ 204,035
Additions for tax positions taken in current year	8,291	11,720	11,986
(Reductions) additions for tax positions taken in prior years	(6,131)	15,177	(883)
Reductions for tax positions settled with tax authorities	—	(29,645)	(125,941)
Reductions for lapse in statute of limitations	(14,574)	(13,706)	—
Balance at December 31	$ 60,329	$ 72,743	$ 89,197

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

	December 31,		
	2025	2024	2023
		(Thousands)	
If recognized, effect to the effective tax rate	$ 57,350	$ 67,105	$ 83,669
Reduction of related deferred tax asset for general business credit carryforwards and NOLs	50,612	60,415	77,013

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 $0.2 million, $0.6 million and $(19.8) million for the years ended December 31, 2025, 2024 and 2023, respectively. Interest and penalties of $3.1 million, $2.9 million, and $2.3 million were included in the Consolidated Balance Sheets as of December 31, 2025, 2024 and 2023, respectively.

In October 2025, the statute of limitation expired for an uncertain tax position, which resulted in a $0.9 million net reduction to the state tax liability and accrued interest reserve and a net increase to the state net operating loss of $10.9 million.

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 and was received by the Company in May 2025. During 2025, the IRS commenced an audit of EQM Midstream Partners, LP (EQM), a wholly owned tax partnership of EQT, for the tax year ended December 31, 2023. As of December 31, 2025, 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 2025.

7. Debt

The table below summarizes the Company's outstanding debt.

	December 31, 2025			December 31, 2024		
	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, 2030	$ 75,000	$ 75,000	$ 75,000	$ 150,000	$ 150,000	$ 150,000
Eureka's revolving credit facility maturing November 13, 2027	285,000	285,000	285,000	320,800	320,800	320,800
Senior notes and debentures:						
EQT's 3.125% notes due May 15, 2026	392,915	392,409	391,037	392,915	391,193	382,994
EQT's 7.75% debentures due July 15, 2026	115,000	114,710	117,315	115,000	114,213	119,590
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 6.500% notes due July 1, 2027	344,921	346,255	352,902	—	—	—
EQT's 3.900% notes due October 1, 2027	936,158	934,640	932,282	1,169,503	1,166,523	1,137,248
EQT's 5.700% notes due April 1, 2028	500,000	494,905	516,035	500,000	492,640	508,695
EQM's 5.500% notes due July 15, 2028	—	—	—	118,683	118,204	117,382
EQT's 5.500% notes due July 15, 2028	45,225	45,060	46,099	—	—	—
EQT's 5.00% notes due January 15, 2029	318,494	316,448	322,902	318,494	315,785	314,357
EQM's 4.50% notes due January 15, 2029	—	—	—	742,923	711,754	711,297
EQT's 4.50% notes due January 15, 2029	734,583	710,802	736,603	—	—	—
EQM's 6.375% notes due April 1, 2029	—	—	—	600,000	608,667	606,774
EQT's 6.375% notes due April 1, 2029	596,725	602,840	618,076	—	—	—
EQT's 7.000% notes due February 1, 2030 (c)	674,800	672,263	733,676	674,800	671,641	718,358
EQM's 7.500% notes due June 1, 2030	—	—	—	500,000	535,671	534,950
EQT's 7.500% notes due June 1, 2030	494,086	522,749	544,162	—	—	—
EQM's 4.75% notes due January 15, 2031	—	—	—	1,100,000	1,045,219	1,039,995
EQT's 4.75% notes due January 15, 2031	1,090,218	1,044,098	1,098,329	—	—	—
EQT's 3.625% notes due May 15, 2031	435,165	431,496	409,651	435,165	430,818	388,111
EQT's 5.750% notes due February 1, 2034	750,000	743,589	784,500	750,000	742,796	744,743
EQM's 6.500% notes due July 15, 2048	—	—	—	80,233	81,338	81,932
EQT's 6.500% notes due July 15, 2048	67,196	68,064	68,722	—	—	—
Total debt	7,855,486	7,800,328	8,032,291	9,368,516	9,324,177	9,299,525
Less: Current portion of debt (d)	507,915	507,119	508,352	320,800	320,800	320,800
Long-term debt	$7,347,571	$7,293,209	$7,523,939	$9,047,716	$9,003,377	$8,978,725

(a) For EQT's and Eureka's revolving credit facilities, the principal value represents carrying value. For all other debt, the principal value less unamortized debt issuance costs, debt discounts and fair value adjustments recorded with the Equitrans Midstream Merger purchase price accounting, as applicable, represents carrying value.

(b) For EQT's and Eureka's revolving credit facilities, the carrying value approximates fair value as their interest rates are based on prevailing market rates; therefore, the Company considers the fair value of EQT's and Eureka's revolving credit facilities to be Level 1 fair value measurements. 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. For all other senior notes, interest rates do not fluctuate.

(d) As of December 31, 2025, the current portion of debt included EQT's 3.125% senior notes and 7.75% debentures. As of December 31, 2024, the current portion of debt included borrowings outstanding under Eureka's revolving credit facility.

Debt Repayments. The Company repaid, redeemed or repurchased the following debt during the year ended December 31, 2025.

Debt Tranche	Principal	Premiums Paid/ (Discounts Received)	Accrued But Unpaid Interest	Total Cost
		(Thousands)		
EQM's 6.500% notes due July 1, 2027 (a) (c)	$ 555,077	$ 14,590	$ 6,754	$ 576,421
EQT's 3.900% notes due October 1, 2027 (a)	233,345	(2,842)	4,070	234,573
EQM's 5.500% notes due July 15, 2028 (b)	73,456	2,878	1,190	77,524
EQM's 7.500% notes due June 1, 2027 (c)	4,069	76	51	4,196
EQM's 4.50% notes due January 15, 2029 (c)	8,338	27	17	8,382
EQM's 6.375% notes due April 1, 2029 (c)	3,265	135	70	3,470
EQM's 7.500% notes due June 1, 2030 (c)	5,536	666	69	6,271
EQM's 4.75% notes due January 15, 2031 (c)	9,616	117	20	9,753
EQM's 6.500% notes due July 15, 2048 (c)	12,989	1,738	37	14,764
EQT's 7.500% notes due June 1, 2027 (d)	495,925	9,299	2,996	508,220
Total	$ 1,401,616	$ 26,684	$ 15,274	$ 1,443,574

(a) On February 24, 2025, the Company announced the commencement of tender offers (the Tender Offers) to purchase all of EQM's outstanding 6.500% senior notes and a specified amount of EQT's outstanding 3.900% senior notes. On March 12, 2025, the Company settled the Tender Offers and repurchased $506.2 million aggregate principal amount of EQM's 6.500% senior notes and $233.3 million aggregate principal amount of EQT's 3.900% senior notes. In addition to call premiums paid (discounts received), the Company paid $2.7 million in fees to dealer managers and other non-lender parties in connection with the Tender Offers.

(b) On April 16, 2025, EQM issued a notice of full redemption to holders of its outstanding 5.500% senior notes, and, on May 1, 2025, EQM redeemed such notes in full.

(c) On July 16, 2025, EQM issued notices of full redemption to holders of each outstanding series of its senior notes, and, on July 31, 2025, EQM redeemed such notes in full. The redeemed notes had an aggregate principal amount of approximately $92.7 million, and, following these redemptions, EQM has no outstanding senior notes.

(d) On December 19, 2025, EQT issued a notice of full redemption to holders of its outstanding 7.500% senior notes, and, on December 30, 2025, EQT redeemed such notes in full.

EQT's Revolving Credit Facility. EQT has a $3.5 billion revolving credit facility governed by that certain Fourth Amended and Restated Credit Agreement, dated as of July 22, 2024 (as amended, the EQT Credit Agreement), among EQT, PNC Bank, National Association, as administrative agent, swing line lender and letter of credit issuer, and the other lenders party thereto. On June 30, 2025, EQT obtained the consent of each of the lenders party to the EQT Credit Agreement to extend the maturity date of the commitments and loans thereunder (the Stated Maturity Date) from July 23, 2029 to July 23, 2030, effective as of July 23, 2025 (the Extension). The terms of the EQT Credit Agreement otherwise remain unchanged. Pursuant to the terms of the EQT Credit Agreement, EQT may request two one-year extensions of the Stated Maturity Date, subject to satisfaction of certain conditions. The Extension is the first such extension.

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, 2025, no single lender in the syndicate for EQT's revolving credit facility held 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, 2025, EQT was in compliance with all provisions and covenants of the EQT Credit Agreement.

As of December 31, 2025 and 2024, the Company had approximately $2 million and $1 million, respectively, of letters of credit outstanding under EQT's revolving credit facility.

During the years ended December 31, 2025, 2024 and 2023, under EQT's revolving credit facility, the maximum amount of outstanding borrowings was $566 million, $2,357 million and $269 million, respectively, the average daily balance was approximately $98 million, $936 million and $40 million, respectively, and interest was incurred at a weighted average annual interest rate of 5.9%, 6.6% and 6.9%, respectively. For all years ended December 31, 2025, 2024 and 2023, EQT incurred commitment fees of 20 basis points on the undrawn portion of its revolving credit facility.

Eureka's Revolving Credit Facility. Through its controlling interest in Eureka Holdings, the Company consolidates Eureka's $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, the Eureka Credit Agreement). On June 30, 2025, Eureka entered into that certain Third Amendment and Master Assignment to Credit Agreement to, among other things, extend the maturity date of the commitments and loans under the Eureka Credit Agreement from November 13, 2025 to November 13, 2027 and reduce the commitment fee spread (calculated based on Eureka's consolidated leverage ratio) from a range of 37.5 to 50 basis points to a range of 32.5 to 45 basis points.

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 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, 2025, Eureka was in compliance with all provisions and covenants of the Eureka Credit Agreement.

As of both December 31, 2025 and 2024, Eureka had no letters of credit outstanding under its revolving credit facility.

During the year ended December 31, 2025, under Eureka's revolving credit facility, the maximum amount of outstanding borrowings was approximately $321 million, the average daily balance was approximately $288 million and interest was incurred at a weighted average annual interest rate of 7.0%. During 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 approximately $330 million, the average daily balance was approximately $328 million and interest was incurred at a weighted average annual interest rate of 7.8%. For the year ended December 31, 2025, Eureka incurred commitment fees ranging from 32.5 to 50 basis points on the undrawn portion of its revolving credit facility. For the period beginning on July 22, 2024 and ending on December 31, 2024, Eureka incurred commitment fees of 50 basis points on the undrawn portion of its revolving credit facility.

EQM Exchange Offers. On February 24, 2025, the Company commenced private offers (the EQM Exchange Offers) to certain eligible holders of EQM's senior notes to exchange any and all outstanding notes issued by EQM (the Existing EQM Notes), including outstanding principal of EQM's 6.500% senior notes due 2027 that remained outstanding following settlement of the Tender Offers, for up to $4,541.8 million aggregate principal amount of new notes issued by EQT (the New EQT Notes) and cash consideration equal to $1.00 per $1,000 principal amount of Existing EQM Notes exchanged. Pursuant to the EQM Exchange Offers, for each $1,000 principal amount of Existing EQM Notes validly tendered on or prior to 5:00 p.m., New York City time, on March 7, 2025 (the Early Tender Date), the holder thereof received $1,000 principal amount of New EQT Notes of the applicable series; for each $1,000 principal amount of Existing EQM Notes validly tendered after the Early Tender Date but on or prior to 5:00 p.m., New York City time, on March 28, 2025 (the Expiration Date), the holder thereof received $950 principal of New EQT Notes of the applicable series.

On April 2, 2025, the Company issued approximately $3,868.9 million of New EQT Notes in exchange for the tender of approximately $3,869.5 million of Existing EQM Notes and paid to holders of the New EQT Notes cash consideration of approximately $3.9 million, which was capitalized as additional debt premium. In addition, the discount received by EQT from holders who validly tendered their Existing EQM Notes after the Early Tender Date but on or prior to the Expiration Date of approximately $0.6 million was capitalized as additional debt discount. In connection with the EQM Exchange Offers, the Company incurred non-lender expenses of approximately $9.6 million in loss on debt extinguishment in the Statement of Consolidated Operations during the year ended December 31, 2025. The maturity date, interest rate and covenants of each New EQT Note are consistent with those of the corresponding Existing EQM Note exchanged.

Consent Solicitation. In conjunction with the Tender Offers and EQM Exchange Offers, the Company solicited and obtained consents with respect to certain proposed amendments to each of the indentures governing the Existing EQM Notes that, upon adoption (which occurred on April 2, 2025), eliminated substantially all of the restrictive covenants, certain events of default and certain other provisions previously contained in such indentures.

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.

As of December 31, 2025, aggregate maturities for EQT's senior notes were approximately $508 million in 2026, $1,281 million in 2027, $545 million in 2028, $1,650 million in 2029, $1,169 million in 2030 and $2,343 million thereafter.

EQT's 1.75% Convertible Notes and Capped Call Transactions. In April 2020, EQT issued $500 million aggregate principal amount of 1.75% convertible senior notes (the Convertible Notes). The Convertible Notes were fully redeemed in January 2024.

In connection with, but separate from, the issuance of the Convertible Notes, 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. In January 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 and the Capped Call Transactions were terminated.

8. Investments in Unconsolidated Entities

Equity Method Investments

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

	December 31, 2025		December 31, 2024	
	Ownership Interest	Carrying Value	Ownership Interest	Carrying Value
		(Thousands)		(Thousands)
MVP Joint Venture (a):				
MVP A	49.3 %	$ 3,097,754	49.3 %	$ 3,469,438
MVP B	47.2 %	42,420	47.2 %	65,292
MVP C	49.3 %	374,629	— %	—
Total MVP Joint Venture		3,514,803		3,534,730
Laurel Mountain Midstream, LLC (b)	31.0 %	47,037	31.0 %	28,757
Other		35,724		20,668
Total		$ 3,597,564		$ 3,584,155

(a) Mountain Valley Pipeline, LLC (the MVP Joint Venture) is a Delaware series limited liability company formed as a joint venture for the purpose of constructing and owning natural gas assets. The MVP Joint Venture has three series, as follows (with each term defined below): MVP A, which owns MVP Mainline; MVP B, which owns MVP Southgate; and MVP C, which owns certain assets associated with MVP Boost. A wholly owned subsidiary of the Company serves as the operator for each series of the MVP Joint Venture.

(b) Laurel Mountain Midstream, LLC (LMM) is a midstream company formed as a joint venture among the Company, Williams Companies Inc. and certain other energy companies for the purpose of owning and operating gathering and processing assets.

Certain of the Company's equity method investments have an unamortized basis difference between the Company's investment carrying value and its proportionate share of the underlying net assets of the investees. To the extent the basis difference is amortizable, the related accretion is reflected in income from investments in the Statements of Consolidated Operations. As of December 31, 2025, the aggregate unamortized basis difference was approximately $1.4 billion.

MVP A. Series A of the MVP Joint Venture (MVP A) was formed for the purpose of constructing and owning the Mountain Valley Pipeline (MVP Mainline). As of December 31, 2025, MVP A's members consisted of the Midstream Joint Venture and affiliates of each of NextEra Energy, Inc. (NextEra), Con Edison Gas Pipeline and Storage, LLC (ConEd), AltaGas Ltd. (AltaGas) and RGC Resources, Inc. (RGC). See "MVP A and MVP C Buy-Out Right" below for a discussion of changes in ownership interests occurring after December 31, 2025.

MVP Mainline 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 and is regulated by the FERC. MVP Mainline entered into service on June 14, 2024 and commenced long-term firm capacity obligations on July 1, 2024.

For the year ended December 31, 2025, the Company's ownership interest in MVP A 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 MVP A.

	Year Ended December 31, 2025	July 22, 2024 to December 31, 2024
	(Thousands)	
Operating revenues	$ 565,312	$ 247,360
Operating income	270,095	126,202
Net income	275,419	129,773

	December 31,	
	2025	2024
	(Thousands)	
Current assets	$ 129,883	$ 204,028
Noncurrent assets	9,419,089	9,535,975
Total assets	$ 9,548,972	$ 9,740,003
Current liabilities	$ 24,218	$ 69,303
Noncurrent liabilities	4,629	1,514
Total liabilities	28,847	70,817
Members' equity	9,520,125	9,669,186
Total liabilities and members' equity	$ 9,548,972	$ 9,740,003

MVP B. Series B of the MVP Joint Venture (MVP B) was formed for the purpose of constructing and owning the MVP Southgate project (MVP Southgate). As of December 31, 2025, MVP B's members consisted of the Company and affiliates of NextEra, AltaGas and RGC.

MVP Southgate is a contemplated interstate pipeline that was approved by the FERC. MVP Southgate was initially designed to extend approximately 75 miles from MVP Mainline 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 an amended project and, among other things, describe certain conditions precedent to the parties' respective obligations regarding MVP Southgate. As amended, the natural gas interstate pipeline would extend approximately 31 miles from the terminus of MVP Mainline in Pittsylvania County, Virginia to planned new delivery points in Rockingham County, North Carolina using 30-inch diameter pipe and have a projected capacity of 0.55 Bcf per day. The proposed 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.

Pending receipt of remaining regulatory approvals, MVP Southgate is expected to be placed into service by mid-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 MVP B.

Under the MVP Joint Venture's limited liability company agreement (the MVP LLC Agreement), the Company is required to provide performance assurance for MVP Southgate, which may take the form of a guarantee from the Company (as a Qualified Guarantor, as defined in the MVP LLC Agreement), a letter of credit or cash collateral. In July 2025, the Company issued a performance guarantee of approximately $14.2 million for MVP Southgate. Upon receipt of the FERC's initial authorization to begin construction of MVP Southgate, the Company's current MVP Southgate performance guarantee will be terminated, and the Company will be required to provide performance assurance equal to 33% of its proportionate share of the remaining capital commitments under MVP Southgate's most recently approved construction budget.

MVP C. Series C of the MVP Joint Venture (MVP C) was formed on November 1, 2025 for the purpose of constructing and owning certain assets associated with the MVP Boost project (MVP Boost). As of December 31, 2025, MVP C's members consisted of the Company and affiliates of NextEra, AltaGas, ConEd and RGC. See "MVP A and MVP C Buy-Out Right" below for a discussion of changes in ownership interests occurring after December 31, 2025.

MVP Boost is a contemplated project to add compression to MVP Mainline, which is projected to increase the capacity on MVP Mainline by 0.6 Bcf per day. As designed, MVP Boost would add compression at three existing compressor stations in West Virginia and construct a new compressor station in Montgomery County, Virginia.

On October 23, 2025, the MVP Joint Venture applied to the FERC for authorization to construct MVP Boost. Pending receipt of regulatory approvals, MVP Boost is expected to be placed into service by mid-2028. MVP Boost is estimated to have a total cost of approximately $400 million to $540 million, excluding AFUDC, of which the Company will fund its proportionate share through capital contributions to MVP C.

Under the MVP LLC Agreement, the Company is required to provide performance assurance for MVP Boost, which may take the form of a guarantee from the Company (as a Qualified Guarantor), a letter of credit or cash collateral. In November 2025, the Company issued a performance guarantee of approximately $14.8 million for MVP Boost. Upon receipt of the FERC's initial authorization to begin construction of MVP Boost, the Company's current MVP Boost performance guarantee will be terminated, and the Company will be required to issue a new performance assurance equal to 33% of its proportionate share of the remaining capital commitments under MVP Boost's most recently approved construction budget.

MVP A and MVP C Buy-Out Right. On November 24, 2025, ConEd entered into a purchase and sale agreement pursuant to which ConEd agreed to sell its approximately 6.60% interest in each of MVP A and MVP C to a third-party investor. On January 2, 2026, the Company provided ConEd notice of its election to exercise its preferential buy-out right in full in accordance with the MVP LLC Agreement. On January 16, 2026, the Company entered into a purchase and sale agreement with ConEd to acquire the Company's pro rata share of ConEd's equity interests in MVP A and MVP C, representing an approximately 3.94% interest in each series. Total consideration for the Company's acquisition of equity interests in MVP A is approximately $200.7 million, of which $98.4 million is expected to be funded by the BXCI Affiliate (defined in Note 9), subject to purchase price adjustments. Total consideration for the Company's acquisition of equity interests in MVP C is approximately $12.5 million, subject to purchase price adjustments. The transaction is expected to close in the first half of 2026, subject to regulatory approvals.

The acquisition of ConEd's remaining 2.66% interest in each series was completed by NextEra in January 2026 pursuant to similar preferential rights under the MVP LLC Agreement.

Investments in Equity Securities

The Investment Fund. The Company holds 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 both December 31, 2025 and 2024, the fair value of the Company's investment in the Investment Fund was approximately $33 million and is 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.

9. The Midstream Joint Venture

In September 2024, the Company, through its wholly owned subsidiary EQM, formed PipeBox LLC (the Midstream Joint Venture) as a wholly owned subsidiary. On December 30, 2024, the Company contributed to the Midstream Joint Venture certain transmission, storage and gathering assets and its ownership interest in MVP A, and an affiliate of Blackstone Credit & Insurance (the BXCI Affiliate) contributed $3.5 billion of cash (such contributions, 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, resulting in the BXCI Affiliate obtaining a noncontrolling interest in the Midstream Joint Venture. The Company retained a controlling voting interest in, and continues to consolidate, the Midstream Joint Venture.

In connection with the Midstream Joint Venture Transaction, on December 30, 2024, certain of the Company's wholly owned subsidiaries and the BXCI Affiliate entered into an amended and restated limited liability company agreement of the Midstream Joint Venture (the JV Agreement). Under the JV Agreement, 40% of available cash flow of the Midstream Joint Venture is distributed to the Company, as holder of the Class A units in the Midstream Joint Venture (Class A Unitholder), and 60% of available cash flow is distributed to the BXCI Affiliate, as holder of the Class B units in the Midstream Joint Venture (Class B Unitholder), until the BXCI Affiliate achieves the Base Return (as defined in the JV Agreement). After the Base Return has been achieved and until the eighth anniversary of the Midstream Joint Venture Transaction, 100% of distributions from the Midstream Joint Venture will be made to the Company. Thereafter, no less than 95% of distributions from the Midstream Joint Venture will be made to the Company and up to 5% of distributions will be made to the BXCI Affiliate, depending on the BXCI Affiliate's ownership interest at the time of such distribution. During the year ended December 31, 2025, the Midstream Joint Venture paid distributions of $354.9 million to the BXCI Affiliate. Distributions from the Midstream Joint Venture to the Company are eliminated in consolidation.

Based on the governing provisions of the JV Agreement, the Company'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 attributable to the noncontrolling interest based on the amounts 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 their recorded amounts and after taking into account any capital transactions between the Company and the BXCI Affiliate.

MVP A Buy-Out Right. As discussed in Note 8, the Company entered into a purchase and sale agreement with ConEd to acquire an approximately 3.94% equity interest in MVP A for consideration of approximately $200.7 million, subject to purchase price adjustments. The acquisition will be funded through capital contributions from the Midstream Joint Venture's members in proportion to their existing ownership interests, and, in exchange, the Midstream Joint Venture will issue additional Class A to the Class A Unitholder and Class B units to the Class B Unitholder to maintain the members' ownership percentages in the Midstream Joint Venture.

10. Common Stock and Income Per Share

As of December 31, 2025, the Company had reserved 16.3 million shares of authorized and unissued EQT common stock for stock compensation plans.

Share Repurchase Program. The Company is authorized to repurchase shares of outstanding EQT common stock under a share repurchase program (the Share Repurchase Program) for an aggregate purchase price of up to $2 billion, excluding fees, commissions and expenses. On December 18, 2024, the Company announced that its Board of Directors approved a two-year extension of the Share Repurchase Program, extending its expiration date to December 31, 2026. The Share Repurchase Program may be suspended, modified or discontinued at any time without prior notice.

From the Share Repurchase Program's inception in 2021 and through December 31, 2025, 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 Company did not repurchase any equity securities during the years ended December 31, 2025 and 2024. For the year ended December 31, 2023, the total number of shares purchased under the Share Repurchase Program was 5,906,159 for an aggregate purchase price of $200.0 million and an average price paid per share of $33.86, in each case excluding fees and brokerage commissions.

Share Issuances. In July 2025, the Company issued 25,229,166 shares of EQT common stock as part of the consideration for the Olympus Energy Acquisition described in Note 11.

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 11.

During 2023 and in January 2024, the Company issued shares of EQT common stock upon settlement of Convertible Notes conversion right exercises. The Convertible Notes were fully redeemed in January 2024.

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 11.

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 redemption, the Convertible Notes. Purchases of treasury shares are calculated using the average share price of EQT common stock during the period. Prior to 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,		
	2025	2024	2023
	(Thousands, except per share amounts)		
Net income attributable to EQT Corporation – Basic income available to shareholders	$ 2,039,247	$ 230,577	$ 1,735,232
Add back: Interest expense on Convertible Notes, net of tax	—	86	7,551
Diluted income available to shareholders	$ 2,039,247	$ 230,663	$ 1,742,783
Weighted average common stock outstanding – Basic	611,571	509,597	380,902
Options, restricted stock, performance awards and stock appreciation rights	4,146	4,625	5,232
Convertible Notes	—	371	27,090
Weighted average common stock outstanding – Diluted	615,717	514,593	413,224
Income per share of common stock attributable to EQT Corporation:			
Basic	$ 3.33	$ 0.45	$ 4.56
Diluted	$ 3.31	$ 0.45	$ 4.22

11. Acquisitions

Olympus Energy Acquisition

On July 1, 2025, the Company completed its acquisition (the Olympus Energy Acquisition) of certain oil and gas properties and related upstream and midstream assets, including approximately 90,000 net acres with approximately 500 million cubic feet (MMcf) per day of net production, from Olympus Energy LLC, Hyperion Midstream LLC and Bow & Arrow Land Company LLC (collectively, Olympus Energy) pursuant to a purchase and sale agreement dated April 22, 2025, by and among EQT, a wholly owned subsidiary of EQT and Olympus Energy.

The purchase price for the Olympus Energy Acquisition consisted of 25,229,166 shares of EQT common stock, with an aggregate value of approximately $1,471 million based on an EQT common stock share price of $58.32 (the last reported per share sale price of EQT common stock on the day prior to the completion of the Olympus Energy Acquisition), and approximately $473 million in cash, each as adjusted pursuant to customary purchase price adjustments and subject to final post-closing purchase price adjustments. The Company funded the cash consideration with cash on hand and borrowings under EQT's revolving credit facility.

Allocation of Purchase Price. The Olympus Energy Acquisition was accounted for as a business combination using the acquisition method. The Company completed the purchase price allocation for the Olympus Energy Acquisition during the fourth quarter of 2025. The table below summarizes the final purchase price and estimated fair values of the assets acquired and liabilities assumed as of July 1, 2025. No goodwill was recognized for the transaction.

		Purchase Price Allocation
		(Thousands)
Consideration:		
Equity	$	1,471,365
Cash		473,360
Total consideration	$	1,944,725
Fair value of assets acquired:		
Derivative instruments, at fair value	$	13,188
Prepaid expenses and other		18
Property, plant and equipment		2,019,892
Amount attributable to assets acquired	$	2,033,098
Fair value of liabilities assumed:		
Accounts payable	$	3,082
Derivative instruments, at fair value		66,711
Other current liabilities		3,657
Asset retirement obligations and other liabilities		14,923
Amount attributable to liabilities assumed	$	88,373

The fair values of the developed and undeveloped natural gas properties acquired in the Olympus Energy Acquisition were measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are Level 3 fair value measurements. Significant inputs used in the valuation of developed and undeveloped properties included commodity prices, projected reserve quantities, estimated future rates of production, projected reserve recovery factors, development plans (including timing and amount of development), future development costs, operating costs and a weighted-average cost of capital. For undeveloped properties, significant inputs also included development plans evaluated from a market participant perspective.

The fair value of the gathering system acquired in the Olympus Energy Acquisition 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 included the replacement cost of similar assets, adjusted for depreciation based on asset age and condition, and adjustments for functional and economic obsolescence based on estimated utilization, recoveries and technological differences relative to newly constructed assets.

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 Olympus Energy Acquisition to the Company's consolidated results of operation subsequent to the completion of the Olympus Energy Acquisition.

	July 1, 2025 through December 31, 2025
	(Thousands)
Sales of natural gas, natural gas liquids and oil	$ 235,388
Gain on derivatives	31,257
Pipeline and other	4,559
Total operating revenues	$ 271,204
Net income attributable to EQT Corporation (a)	$ 108,117

(a) Net income attributable to EQT Corporation includes $29.1 million of transaction costs related to the Olympus Energy Acquisition recognized during the year ended December 31, 2025.

Pro forma results of operations are not presented as the impact of the Olympus Energy Acquisition was not significant to the Company's consolidated financial statements.

Equitrans Midstream Merger

On July 22, 2024, the Company completed its acquisition (the Equitrans Midstream Merger) of Equitrans Midstream. The purchase price for the Equitrans Midstream Merger consisted of 152,427,848 shares of EQT common stock, with an aggregate value of approximately $5.5 billion. 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 following the Equitrans Midstream Merger closing date and 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. Upon completion of the Equitrans Midstream Merger, the pre-existing contractual relationships between the Company and Equitrans Midstream were effectively settled.

The Equitrans Midstream Merger was accounted for as a business combination using the acquisition method. The Company completed the purchase price allocation for the Equitrans Midstream Merger during the second quarter of 2025, resulting in purchase accounting adjustments to deferred income taxes based on updated income tax computations as well as investments in unconsolidated entities and property, plant and equipment based on updated appraisal estimates.

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 purchase price 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 upstream assets from THQ Appalachia I, LLC and 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 Tug Hill and XcL Midstream Acquisition was accounted for 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.

12. Divestitures

Non-Core Asset Divestiture. In December 2025, the Company completed the divestiture of certain non-core upstream and midstream assets (the Non-Core Asset Divestiture) for total consideration of $0.6 million. The transaction was accounted for as a normal retirement, resulting in the derecognition of associated asset retirement obligations of approximately $97 million.

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 to Equinor USA Onshore Properties Inc. and its affiliates (collectively, the Equinor Parties). The carrying amount of the divested assets was approximately $523 million, primarily consisting of property, plant and equipment, net of associated liabilities. In exchange, as consideration, the Company received cash from the Equinor Parties 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.

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.

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 to the Equinor Parties. The carrying amount of the divested assets was approximately $772 million, primarily consisting of property, plant and equipment, net of associated liabilities. In exchange, as consideration, the Company received from the Equinor Parties cash of $1.25 billion, subject to customary post-closing purchase price adjustments.

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.

13. Commitments and Contingencies

Contractual Commitments

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, 2025 were $13.2 billion, composed of $1.1 billion in 2026, $1.1 billion in 2027, $1.0 billion in 2028, $0.9 billion in 2029, $0.9 billion in 2030 and $8.2 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, 2025 were $389.3 million, composed of $230.5 million in 2026, $116.6 million in 2027, $41.1 million in 2028, $0.6 million in 2029, $0.4 million in 2030 and $0.1 million thereafter.

See Note 15 for a summary of undiscounted future minimum lease payments owed to lessors by the Company as lessee pursuant to contractual agreements in effect as of December 31, 2025.

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 when it determines, based on historical experience and matter-specific facts, 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 alleged that certain statements made by EQT regarding its merger with Rice Energy Inc. in 2017 were materially false and violated various federal securities laws. Pursuant to the complaint, the plaintiffs sought 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's common 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 settlement of the Securities Class Action referred to below does not resolve these matters.

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 June 2024 Mediation), which did not result in resolution. In the second quarter of 2024, the Company recorded an accrual for estimated loss contingencies related to the Securities Class Action in an amount equal to the settlement offer the Company tendered at the June 2024 Mediation of $17.5 million.

Following the June 2024 Mediation, the parties filed various motions, including motions for summary judgment and motions to exclude expert testimony. While these motions remained pending, on May 12, 2025, the parties to the Securities Class Action participated in a second mediation, at which it was agreed that the Company would pay $167.5 million to the plaintiffs to settle the Securities Class Action. The court issued a final order and judgment approving the settlement on November 4, 2025. The settlement does not constitute an admission of wrongdoing or liability by the Company or the other defendants, who have agreed to the settlement to avoid further protracted and expensive litigation.

In the second quarter of 2025, the Company recorded an increase to its accrual for estimated loss contingencies related to the Securities Class Action of $150.0 million, resulting in a total reserve equal to the settlement amount agreed upon at the May 12, 2025 mediation of $167.5 million. During the third quarter of 2025, the Company paid the settlement amount in full and received insurance recoveries of approximately $16 million.

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 $4 million was recorded in asset retirement obligations and other liabilities credits in the Consolidated Balance Sheet as of December 31, 2025.

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.

14. Share-Based Compensation Plans

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

	Years Ended December 31,		
	2025	2024	2023
		(Thousands)	
Incentive Performance Share Unit Programs	$ 14,505	$ 20,919	$ 23,915
Restricted stock awards	41,310	25,473	20,119
Stock appreciation rights	—	—	4,056
Other programs, including non-employee director awards	3,784	3,596	3,110
Total share-based compensation expense (a)	$ 59,599	$ 49,988	$ 51,200

(a) For the years ended December 31, 2025, 2024 and 2023, share-based compensation expense of $2.7 million, $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.

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.

There was no cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2025 and 2023. Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2024 was $5.1 million. During the years ended December 31, 2025, 2024 and 2023, share-based payment arrangements paid in stock generated tax benefits of $12.3 million, $7.7 million and $16.5 million, respectively. Cash paid for taxes related to net settlement of share-based incentive awards for the years ended December 31, 2025, 2024 and 2023 were $54.2 million, $102.9 million and $41.8 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):

- 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;
- 2024 Incentive Performance Share Unit Program (2024 Incentive PSU Program) under the 2020 LTIP; and
- 2025 Incentive Performance Share Unit Program (2025 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 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, 2024, and 2025 are earned based on:

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

The 2021 Incentive PSU Program, 2023 Incentive PSU Program, 2024 Incentive PSU Program, and 2025 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 2021 Incentive PSU Program, 2022 Incentive PSU Program, 2023 Incentive PSU Program, 2024 Incentive PSU Program, and 2025 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 January 1, 2023	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
Granted in Period	377,570	74.14	27,993,040
Granted from Multiplier	649,020	75.32	48,884,186
Vested	(1,213,385)	75.32	(91,392,158)
Forfeited	(66,009)	54.23	(3,579,668)
Outstanding at December 31, 2025	1,039,547	$ 25.93	$ 26,959,680

Total capitalized compensation costs related to the Incentive PSU Programs for the years ended December 31, 2025, 2024 and 2023 were $0.9 million, $0.5 million and $0.6 million, respectively. As of December 31, 2025, unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2025 Incentive PSU Program and 2024 Incentive PSU Program of $18.0 million and $4.6 million, 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,				
	2025	2024	2023 (a)	2022	2021 (a)
Risk-free rate	4.22%	4.35%	4.16%	1.52%	0.18%
Volatility factor	43.15%	48.82%	59.31%	65.38%	72.50%
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.

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 1,720,700, 982,990 and 953,270 restricted stock unit equity awards to employees of the Company during the years ended December 31, 2025, 2024 and 2023, 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, 2025, 2024 and 2023, the weighted average fair value of these restricted stock unit grants, based on the grant date fair value of EQT common stock, was approximately $52.80, $34.54 and $31.88, respectively.

The total fair value of restricted stock unit equity awards vested during the years ended December 31, 2025, 2024 and 2023 was $45.5 million, $155.5 million and $23.5 million, respectively. Total capitalized compensation costs related to the restricted stock unit equity awards was $19.4 million, $9.6 million and $5.7 million for the years ended December 31, 2025, 2024 and 2023, respectively.

As of December 31, 2025, $66.2 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, 2025.

Restricted Stock – Equity Settled	Nonvested Shares	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2023	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 (a)	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
Granted	1,720,700	52.80	90,858,021
Vested	(1,458,200)	31.22	(45,519,859)
Forfeited	(140,937)	35.00	(4,933,212)
Outstanding at December 31, 2025	3,545,732	$ 43.58	$ 154,509,335

(a) In conjunction with the Equitrans Midstream Merger, the Company assumed all outstanding and unvested share-based compensation awards of Equitrans Midstream and converted those awards into restricted stock equity awards.

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 2025, 2024 and 2023.

	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, 2025, 2024 and 2023 was $2.7 million, $0.7 million and $1.4 million, respectively.

The following table summarizes option activity as of December 31, 2025.

Non-Qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2025	1,195,336	$ 12.14		
Exercised	(95,874)	23.93		
Outstanding and Exercisable at December 31, 2025	1,099,462	$ 11.11	1.3 years	$ 46,713,420

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 305,556 non-employee director share-based awards, including accrued dividends, were outstanding as of December 31, 2025. A total of 36,630, 70,930 and 66,300 share-based awards were granted to non-employee directors during the years ended December 31, 2025, 2024 and 2023, 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 $50.74, $36.14 and $33.31 for the years ended December 31, 2025, 2024 and 2023, respectively.

2026 Awards

Effective in 2026, the Compensation Committee adopted the 2026 Incentive Performance Share Unit Program (2026 Incentive PSU Program) under the 2020 LTIP. The 2026 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 approximately 505,000 share units were granted under the 2026 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, 2026 through December 31, 2028.

Effective in 2026, the Compensation Committee granted approximately 1,170,000 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.

15. 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, 2025 and 2024, the Company was not a lessor.

The following table summarizes the Company's lease costs.

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Operating lease costs	$ 43,002	$ 41,991	$ 26,755
Finance lease costs	9,585	5,546	2,414
Variable and short-term lease costs	38,935	33,475	24,151
Total lease costs (a)	$ 91,522	$ 81,012	$ 53,320

(a) Includes drilling rig lease costs capitalized to property, plant and equipment of $47.9 million, $50.5 million and $40.8 million, respectively, of which $30.8 million, $33.1 million and $24.5 million, respectively, were operating lease costs for the years ended December 31, 2025, 2024 and 2023.

The following table summarizes the cash paid for operating and financing lease liabilities reported in the Statements of Consolidated Cash Flows. Cash paid for operating lease liabilities is presented in other items, net as a cash flow from operating activity, and cash paid for finance lease liabilities is presented in other financing activities as a cash flow from financing activity.

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Operating lease liabilities	$ 21,155	$ 13,595	$ 10,078
Finance lease liabilities	6,347	4,232	2,305

For the Company's operating leases, as of December 31, 2025, 2024 and 2023, the weighted average remaining term was 2.4 years, 3.4 years and 1.6 years, respectively, and the weighted average discount rate was 5.1%, 5.3% and 4.7%, respectively. For the Company's finance leases, as of December 31, 2025, 2024 and 2023, the weighted average remaining term was 5.6 years, 6.8 years and 3.8 years, respectively, and the weighted average discount rate was 5.1%, 5.1% and 4.8%, 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 asset retirement obligations and other liabilities, respectively, in the Consolidated Balance Sheets. The following table summarizes the Company's right-of-use assets and lease liabilities.

	December 31,	
	2025	2024
	(Thousands)	
Right-of-Use Assets		
Operating	$ 74,111	$ 60,496
Finance	35,650	34,803
Total right-of-use assets	$ 109,761	$ 95,299
Lease Liabilities		
Current lease liabilities		
Operating	$ 51,042	$ 36,275
Finance	7,082	5,603
Total current lease liabilities	58,124	41,878
Noncurrent lease liabilities		
Operating	27,369	29,391
Finance	29,973	29,263
Total noncurrent lease liabilities	57,342	58,654
Total lease liabilities	$ 115,466	$ 100,532

The following table summarizes the Company's lease payment obligations as of December 31, 2025.

	Operating Lease	Finance Lease	Total Lease
		(Thousands)	
2026	$ 53,639	$ 8,722	$ 62,361
2027	10,859	8,355	19,214
2028	7,915	7,058	14,973
2029	5,972	5,879	11,851
2030	4,885	4,697	9,582
Thereafter	350	7,705	8,055
Total lease payment obligations	83,620	42,416	126,036
Less: Imputed interest	5,209	5,361	10,570
Present value of lease liabilities	$ 78,411	$ 37,055	$ 115,466

16. Concentrations of Credit Risk

Revenues and related accounts receivable from the Company's Upstream 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, 2025 and 2024, approximately 94% and 96%, 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, 2025, 2024 and 2023.

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, 2025, 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, 2025, 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 a significant 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,	
	2025	2024
	(Thousands)	
Capitalized costs		
Proved properties	$ 35,129,865	$ 31,986,473
Unproved properties	1,656,045	1,563,440
Total capitalized costs	36,785,910	33,549,913
Less: Accumulated depreciation and depletion	14,344,974	12,489,317
Net capitalized costs	$ 22,440,936	$ 21,060,596

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Costs incurred (a)			
Property acquisition:			
Proved properties (b)	$ 1,522,869	$ 410,805	$ 4,142,621
Unproved properties (c)	390,103	98,007	575,130
Exploration	3,601	2,735	3,330
Development	1,725,438	1,848,000	1,782,428

(a) Amounts for all years presented exclude costs related to facilities, information technology and other corporate items. Amounts for 2025 and 2024 exclude costs related to midstream assets, while amounts for 2023 include such costs.

(b) Amounts in 2025 include $1,234.5 million and $288.4 million for wells and leases, respectively, acquired in the Olympus Energy Acquisition. 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. 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.

(c) Amounts in 2025 include $235.5 million for unproved properties acquired in the Olympus Energy Acquisition. Amounts in 2024 include $10.8 million for unproved properties received as consideration for the First NEPA Non-Operated Asset Divestiture. Amounts in 2023 include $523.0 million for unproved properties acquired in the Tug Hill and XcL Midstream Acquisition.

Results of Operations for Producing Activities

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

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Sales of natural gas, NGLs and oil	$ 7,726,712	$ 4,934,366	$ 5,044,768
Transportation and processing	1,532,090	1,915,616	2,157,260
Production	388,696	377,007	254,700
Operating and maintenance	23,013	37,951	—
Exploration	3,601	2,735	3,330
Depreciation and depletion	2,263,105	2,016,670	1,732,142
(Gain) loss on sale/exchange of long-lived assets	(31,513)	(764,431)	17,445
Impairment and expiration of leases	50,341	97,368	109,421
Income tax expense	851,939	316,377	187,463
Results of operations from producing activities, excluding corporate overhead	$ 2,645,440	$ 935,073	$ 583,007

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 23 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, 2025. 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 uses 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,		
	2025	2024	2023
		(MMcfe)	
Natural gas, NGLs and oil			
Proved developed and undeveloped reserves:			
Balance at January 1	26,264,669	27,596,694	25,002,589
Revision of previous estimates	(27,073)	(1,079,677)	(1,402,039)
Purchase of hydrocarbons in place	1,768,560	413,040	2,600,667
Sale of hydrocarbons in place	(22,027)	(1,562,849)	—
Extensions, discoveries and other additions	2,444,717	3,125,620	3,411,750
Production	(2,382,367)	(2,228,159)	(2,016,273)
Balance at December 31	28,046,479	26,264,669	27,596,694
Proved developed reserves:			
Balance at January 1	18,804,929	19,558,176	17,513,645
Balance at December 31	20,580,992	18,804,929	19,558,176
Proved undeveloped reserves:			
Balance at January 1	7,459,740	8,038,518	7,488,944
Balance at December 31	7,465,487	7,459,740	8,038,518

	Years Ended December 31,		
	2025	2024	2023
		(MMcf)	
Natural gas			
Proved developed and undeveloped reserves:			
Balance at January 1	24,545,229	25,795,134	23,824,887
Revision of previous estimates	(15,493)	(917,676)	(1,461,305)
Purchase of natural gas in place	1,768,120	395,423	2,012,159
Sale of natural gas in place	(16,145)	(1,562,849)	—
Extensions, discoveries and other additions	2,373,231	2,921,638	3,326,736
Production	(2,238,652)	(2,086,441)	(1,907,343)
Balance at December 31	26,416,290	24,545,229	25,795,134
Proved developed reserves:			
Balance at January 1	17,440,191	18,186,432	16,541,017
Balance at December 31	19,237,547	17,440,191	18,186,432
Proved undeveloped reserves:			
Balance at January 1	7,105,038	7,608,702	7,283,870
Balance at December 31	7,178,743	7,105,038	7,608,702

	Years Ended December 31,		
	2025	2024	2023
		(Mbbl)	
NGLs			
Proved developed and undeveloped reserves:			
Balance at January 1	271,908	285,345	186,141
Revision of previous estimates	750	(24,332)	11,558
Purchase of NGLs in place	73	2,529	90,604
Sale of NGLs in place	(902)	—	—
Extensions, discoveries and other additions	10,317	30,391	13,592
Production	(22,168)	(22,025)	(16,550)
Balance at December 31	259,978	271,908	285,345
Proved developed reserves:			
Balance at January 1	217,786	218,523	154,921
Balance at December 31	215,302	217,786	218,523
Proved undeveloped reserves:			
Balance at January 1	54,122	66,822	31,220
Balance at December 31	44,676	54,122	66,822

	Years Ended December 31,		
	2025	2024	2023
	(Mbbl)		
Oil			
Proved developed and undeveloped reserves:			
Balance at January 1	14,664	14,915	10,142
Revision of previous estimates	(2,680)	(2,669)	(1,680)
Purchase of oil in place	—	407	7,481
Sale of oil in place	(78)	—	—
Extensions, discoveries and other additions	1,598	3,606	577
Production	(1,784)	(1,595)	(1,605)
Balance at December 31	11,720	14,664	14,915
Proved developed reserves:			
Balance at January 1	9,669	10,101	7,183
Balance at December 31	8,605	9,669	10,101
Proved undeveloped reserves:			
Balance at January 1	4,995	4,814	2,959
Balance at December 31	3,115	4,995	4,814

The change in reserves during the year ended December 31, 2025 resulted from the following:

- Conversions of 2,380 billion cubic feet equivalent (Bcfe) of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 2,445 Bcfe, which exceeded 2025 production of 2,382 Bcfe. Extensions, discoveries and other additions included an increase of 1,605 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2025 reserve development that expanded the number of the Company's proven locations and additions to the Company's five-year drilling plan, 393 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 133 Bcfe from the extension of lateral lengths of proved undeveloped reserves and 314 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 560 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 42 Bcfe to proved undeveloped locations primarily related to revisions to lateral lengths and type curves.
- Positive revisions to proved undeveloped locations of 291 Bcfe due primarily to changes in ownership interests.
- Negative revisions of 165 Bcfe primarily from proved developed locations as a result of negative curve revisions.
- Positive revisions of 449 Bcfe from proved developed locations as a result of higher pricing, impacting well economics.
- Purchase of hydrocarbons in place of 1,768 Bcfe in connection with the Olympus Energy Acquisition described in Note 11.
- Sale of natural gas in place of 22 Bcfe in connection with the Non-Core Asset Divestiture described in Note 12.

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

- Conversions of 2,637 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 12.
- Sale of natural gas in place of 1,563 Bcfe in the NEPA Non-Operated Asset Divestitures described in Note 12.

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 11.

Standardized Measure of Discounted Future Net 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,		
	2025	2024	2023
		(Thousands)	
Future cash inflows (a)	$ 80,216,863	$ 44,871,509	$ 52,916,665
Future production costs (b)	(21,496,216)	(18,979,056)	(24,357,033)
Future development costs	(4,456,051)	(4,352,890)	(4,298,372)
Future income tax expenses	(11,001,125)	(4,445,354)	(5,230,629)
Future net cash flows	43,263,471	17,094,209	19,030,631
10% annual discount for estimated timing of cash flows	(21,953,285)	(9,095,069)	(9,768,282)
Standardized measure of discounted future net cash flows	$ 21,310,186	$ 7,999,140	$ 9,262,349

(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 differentials. Regional differentials 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,		
	2025	2024	2023
Natural gas for NYMEX ($/MMBtu)	$ 3.387	$ 2.130	$ 2.637
Less: Regional differentials ($/MMBtu)	0.786	0.741	1.029
Natural gas price ($/Mcf)	2.749	1.468	1.700
NGLs price ($/Bbl)	26.97	29.28	28.44
Oil for West Texas Intermediate (WTI) ($/Bbl)	66.01	76.32	78.21
Less: Regional differentials ($/Bbl)	15.29	16.87	14.35
Oil price ($/Bbl)	50.72	59.45	63.86

(b) Includes approximately $2,629 million, $2,553 million and $2,443 million for future plugging and abandonment costs as of December 31, 2025, 2024 and 2023, 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, 2025 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1,265 million, $1,104 million and $61 million, respectively.

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

	Years Ended December 31,		
	2025	2024	2023
	(Thousands)		
Net sales and transfers of natural gas and oil produced	$ (5,782,913)	$ (2,603,792)	$ (2,632,808)
Net changes in prices, production and development costs	16,980,282	(1,237,271)	(48,739,248)
Extensions, discoveries and improved recovery, net of related costs	292,028	464,496	6,347,387
Development costs incurred	1,281,816	1,432,315	1,296,380
Net purchase of minerals in place	1,874,429	269,453	2,131,567
Net sale of minerals in place	(3,053)	(692,019)	—
Revision of previous estimates	135,348	(263,191)	(2,768,922)
Accretion of discount	799,914	926,235	4,006,452
Net change in income taxes	(2,438,815)	411,999	9,190,460
Timing and other	172,010	28,566	366,557
Net increase (decrease)	13,311,046	(1,263,209)	(30,802,175)
Balance at January 1	7,999,140	9,262,349	40,064,524
Balance at December 31	$ 21,310,186	$ 7,999,140	$ 9,262,349

Following the completion of the Equitrans Midstream Merger as described in Note 11, 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 9, 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 the effectiveness 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, 2025. 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, 2025.

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

Changes in Internal Control over Financial Reporting

There were no changes in 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 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

During the fourth quarter of 2025, 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 2026 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, 2025:

- 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 non-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 our separately-designated standing Audit Committee and the members of the Audit Committee;
- Information required by Item 407(d)(5) of Regulation S-K with respect to our audit committee financial expert; and
- Information required by Item 408(b) of Regulation S-K with respect to our insider trading policy.

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 18, 2026)."

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 https://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 2026 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, 2025:

- 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 2026 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, 2025.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2025 with respect to shares of EQT 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), 2025 Employee Stock Purchase Plan (2025 ESPP), 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)	3,615,911	(2)	$ 11.11	(3)	15,467,559	(4)
Equity Compensation Plans Not Approved by Shareholders (5)	69,795	(6)	N/A		93,221	(7)
Total	3,685,706		$ 11.11		15,560,780	

(1) Consists of the 2020 LTIP, 2019 LTIP, 2014 LTIP, 2009 LTIP, the 2025 ESPP 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) 2,136,706 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 1,068,353 target awards and dividend reinvestments thereon)), (ii) 315,315 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) 23,897 shares subject to outstanding directors' deferred stock units under the 2019 LTIP, inclusive of dividend reinvestments thereon, (v) 99,462 shares subject to outstanding stock options under the 2014 LTIP, (vi) 35,809 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon; and (vii) 4,721 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 1.3 years as of December 31, 2025.

(4) Consists of (i) 14,467,559 shares available for future issuance under the 2020 LTIP and (ii) 1,000,000 shares available for future issuance under the 2025 ESPP in which the first purchase commenced in January 2026.

(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, 2025.

(7) Consists entirely of shares available for future issuance under the 2005 DDCP as of December 31, 2025.

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 2026 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, 2025.

Item 14. Principal Accountant Fees and Services

Information required by Item 9(e) of Schedule 14A with respect to our principal accountant's fees and services is incorporated herein by reference from our definitive proxy statement relating to the 2026 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, 2025.

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, 2025

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:					
2025	$ 257,218	$ 31,798	$ —	$ (34,556)	$ 254,460
2024	$ 290,812	$ 21,564	$ —	$ (55,158)	$ 257,218
2023	$ 365,140	$ 12,549	$ —	$ (86,877)	$ 290,812

See Note 6 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.
2.03+	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.
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	Amended and Restated Bylaws of EQT Corporation (as amended through October 16, 2025).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on October 20, 2025.
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.
4.03(l)	Nineteenth Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 6.500% Senior Notes due 2027 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on April 3, 2025.
4.03(m)	Twentieth Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 5.500% Senior Notes due 2028 were issued.	Incorporated herein by reference to Exhibit 4.7 to Form 8-K (#001-3551) filed on April 3, 2025.
4.03(n)	Twenty-First Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 4.50% Senior Notes due 2029 were issued.	Incorporated herein by reference to Exhibit 4.9 to Form 8-K (#001-3551) filed on April 3, 2025.
4.03(o)	Twenty-Second Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 6.375% Senior Notes due 2029 were issued.	Incorporated herein by reference to Exhibit 4.11 to Form 8-K (#001-3551) filed on April 3, 2025.
4.03(p)	Twenty-Third Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 7.500% Senior Notes due 2030 were issued.	Incorporated herein by reference to Exhibit 4.13 to Form 8-K (#001-3551) filed on April 3, 2025.

Exhibit	Description	Method of Filing
4.03(q)	Twenty-Fourth Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 4.75% Senior Notes due 2031 were issued.	Incorporated herein by reference to Exhibit 4.15 to Form 8-K (#001-3551) filed on April 3, 2025.
4.03(r)	Twenty-Fifth Supplemental Indenture, dated as of April 2, 2025, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which EQT Corporation's 6.500% Senior Notes due 2048 were issued.	Incorporated herein by reference to Exhibit 4.17 to Form 8-K (#001-3551) filed on April 3, 2025.
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.	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 April 6, 2018, adopted, executed and agreed as of February 5, 2020.	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.
10.02(c)+	Second Amendment to Third Amended and Restated Limited Liability Company Agreement of Mountain Valley Pipeline, LLC, dated April 6, 2018, adopted, executed and agreed as of November 1, 2025.	Filed herewith as Exhibit 10.02(c).
10.03(a)+	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.
10.03(b)	First Amendment to the Amended and Restated Limited Liability Company Agreement of PipeBox LLC, dated January 16, 2026.	Filed herewith as Exhibit 10.03(b).
10.04	Registration Rights Agreement, dated July 1, 2025, by and among EQT Corporation and certain security holders thereof party thereto, including Olympus Energy Holdings LLC, HNP Holdco LP and HNP Holdco II LLC.	Incorporated herein by reference to Exhibit 4.3 to Form S-3ASR Registration Statement (333-288464) filed on July 2, 2025.
10.05(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.
10.05(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.
10.06(a)*	EQT Corporation 2009 Long-Term Incentive Plan (as amended and restated through July 11, 2012).	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q (#001-3551) for the quarter ended June 30, 2012.
10.06(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants).	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.06(c)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants).	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.07(a)*	EQT Corporation 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 1, 2014.
10.07(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2014.

Exhibit	Description	Method of Filing
10.08(a)*	EQT Corporation 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#001-3551) filed on July 15, 2019.
10.08(b)*	Form of Restricted Stock Unit Award Agreement (Standard) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.08(c)*	Form of Participant Award Agreement (Stock Option) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.09(a)*	EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#333-237953) filed on May 1, 2020.
10.09(b)*	Amendment to EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated by reference to Exhibit 99.2 to Form S-8 (#333-264423) filed on April 21, 2022.
10.09(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.
10.10(a)*	Form of Restricted Stock Unit Award Agreement (Standard)	Incorporated herein by reference to Exhibit 10.10(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.10(b)*	Form of Restricted Stock Unit Award Agreement (Non-Employee Directors).	Incorporated herein by reference to Exhibit 10.06(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.11*	Form of EQT Corporation Short-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 4, 2020.
10.12(a)*	Form of Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.12(b)*	Form of Participant Award Agreement under Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.13*	Form of Participant Award Agreement (Stock Option).	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.14*	EQT Corporation Executive Severance Plan and Form of Participation Notice.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 20, 2020.
10.15(a)*	2005 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014).	Incorporated herein by reference to Exhibit 10.09 to Form 10-K (#001-3551) for the year ended December 31, 2014.
10.15(b)*	Amendment to 2005 Directors' Deferred Compensation Plan (as amended October 2, 2018).	Incorporated herein by reference to Exhibit 10.5 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
10.16*	Form of Indemnification Agreement between EQT Corporation and executive officers and outside directors.	Incorporated herein by reference to Exhibit 10.18 to Form 10-K (#001-3551) for the year ended December 31, 2008.
10.17*	Separation and Release Agreement, dated November 13, 2017, among EQT Corporation, EQT RE, LLC and Daniel J. Rice IV.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on November 17, 2017.

Exhibit	Description	Method of Filing
10.18(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.
10.18(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.
10.18(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.
10.18(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.
10.18(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.
10.19*	Offer Letter, dated January 6, 2020, between EQT Corporation and William E. Jordan.	Incorporated herein by reference to Exhibit 10.29(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(a)*	Offer Letter, dated July 18, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(b)*	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated August 5, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.20(c)*	Relocation Expense Reimbursement Agreement, dated July 24, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.21*	Offer Letter, dated July 16, 2019, between EQT Corporation and Lesley Evancho.	Incorporated herein by reference to Exhibit 10.31(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
19	EQT Corporation Insider Trading Policy	Incorporated herein by reference to Exhibit 19 to Form 10-K (#001-3551) for the year ended December 31, 2024.
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.

Exhibit	Description	Method of Filing
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.

*Management contract or compensatory plan or 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 18, 2026

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 18, 2026
/s/ JEREMY T. KNOP Jeremy T. Knop (Principal Financial Officer)	Chief Financial Officer	February 18, 2026
/s/ TODD M. JAMES Todd M. James (Principal Accounting Officer)	Chief Accounting Officer	February 18, 2026
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 18, 2026
/s/ LEE M. CANAAN Lee M. Canaan	Director	February 18, 2026
/s/ FRANK C. HU Frank C. Hu	Director	February 18, 2026
/s/ KATHRYN J. JACKSON Kathryn J. Jackson	Director	February 18, 2026
/s/ THOMAS F. KARAM Thomas F. Karam	Chair	February 18, 2026
/s/ JOHN F. MCCARTNEY John F. McCartney	Director	February 18, 2026
/s/ DANIEL J. RICE IV Daniel J. Rice IV	Director	February 18, 2026
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 18, 2026
/s/ HALLIE A. VANDERHIDER Hallie A. Vanderhider	Director	February 18, 2026

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