REFINITIV

DELTA REPORT

10-K

SM - SM ENERGY CO

10-K - DECEMBER 31, 2024 COMPARED TO 10-K - DECEMBER 31, 2023

The following comparison report has been automatically generated

TOTAL DELTAS	4718
CHANGES	675
DELETIONS	2077
ADDITIONS	1966

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2023 December 31, 2024
or
☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission file number 001-31539

SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**41-0518430**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Lincoln Street, Suite 3200, Denver, Colorado	**80203**
(Address of principal executive offices)	(Zip Code)

(303) 861-8140
(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, $0.01 par value	**SM**	**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 emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

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

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

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

The aggregate market value of the 116,456,585 77,905,978 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on June 30, 2023 June 28, 2024, the last business day of the registrant's most recently completed second fiscal quarter, of $31.63 $43.23 per share, as reported on the New York Stock Exchange, was $3,683,521,784. $3,367,875,429. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 8, 2024 January 31, 2025, the registrant had 115,746,540 114,461,934 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III of this report is incorporated by reference from portions of the registrant's Definitive Proxy Statement on Schedule 14A relating to its 2024 2025 annual meeting of stockholders, to be filed within 120 days after December 31, 2023 December 31, 2024.

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Cautionary Information about Forward-Looking Statements

This Annual Report on Form 10-K ("Form 10-K" or "this report") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended ("Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). All statements included in this report, other than statements of historical facts, fact, that address activities, conditions, events, or developments with respect to our financial condition, results of operations, business prospects or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "could," "estimate," "expect," "forecast," "goal," "intend," "pending," "plan," "potential," "projected," "seek," "target," "will," and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear throughout this report, and include statements about such matters as:

- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer reallocation of capital, investment, plans with respect to future dividend payments, debt repayments or redemptions, or equity repurchases, capital markets activities, environmental, social, and governance ("ESG") goals and initiatives, and our outlook on our future financial condition or results of operations;
- risks related to the integration of the Uinta Basin Acquisition, including our ability to realize the expected benefits of the Uinta Basin Acquisition or any business disruptions that could result from the Uinta Basin Acquisition; refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for discussion and the definition of the Uinta Basin Acquisition;
- the amount and nature of future capital expenditures, the resilience of our assets to declining commodity prices, the ability of our assets to generate strong returns in the current macroeconomic environment, and the availability of liquidity and capital resources to fund capital expenditures;
- our outlook on prices for future crude oil, natural gas, and natural gas liquids (also referred to throughout this report as "oil," "gas," and "NGLs," respectively), well costs, service costs, production costs, and general and administrative costs, and the effects of inflation, tariffs or trade restrictions on each of these;
- armed conflict, political instability, or civil unrest in oil and gas producing regions and transportation shipping channels, including instability in the Middle East, the wars and armed conflicts between Russia and Ukraine, and among Israel and Hamas, Hezbollah, and Iran and its proxy forces, and related potential effects on laws and regulations, or the imposition of economic or trade sanctions; sanctions ("War and Geopolitical Instability");
- any changes to the borrowing base or aggregate revolving lender commitments under, or the maturity date of, our Seventh Amended and Restated Credit Agreement, as amended ("Credit Agreement");
- cash flows, liquidity, interest and related debt service expenses, changes in our effective tax rate, and our ability to repay debt in the future;
- our drilling and completion activities and other exploration and development activities, each of which could be affected by supply chain disruptions and inflation, tariffs or trade restrictions, our ability to obtain permits and governmental approvals, and plans by us, our joint development partners, and/or other third-party operators;
- possible or expected acquisitions and divestitures, including the possible divestiture or farm-out of, or farm-in or joint development of, certain properties;
- oil, gas, and NGL reserve estimates and estimates of both future net revenues and the present value of future net revenues associated with those reserve estimates, as well as the conversion of proved undeveloped reserves to proved developed reserves;
- our expected future production volumes, identified drilling locations, as well as drilling prospects, inventories, projects and programs;
- changes in proposed or final federal income tax laws and regulations or exposure to additional income tax liabilities; and
- other similar matters, such as those discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. We caution you that forward-looking statements are not guarantees of future performance and these statements are subject to known and unknown risks and uncertainties, which may cause our actual results or performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Factors that may cause our financial condition, results of operations, business prospects or economic performance to differ from expectations include the factors discussed in Part I, Item 1A, *Risk Factors* below and elsewhere in this report.

The forward-looking statements in this report speak only as of the filing of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by applicable securities laws.

Glossary

The oil and gas terms and other terms defined in this section are used throughout this report. The definitions of the terms "developed reserves," "exploratory well," "field," "proved reserves," and "undeveloped reserves" have been abbreviated from the respective definitions under Rule 4-10(a) of Regulation S-X. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through on the Securities and Exchange Commission's ("SEC") website at www.sec.gov.

Ad valorem tax. A tax based on the value of real estate or personal property.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

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

BBtu. One billion British thermal units.

Bcf. One billion cubic feet, used in reference to gas.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas to one Bbl of oil or NGLs.

Btu. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Completion. The installation of equipment for production of oil, gas, and/or NGLs, or in the case of a dry hole, the reporting to the applicable authority that the well has been abandoned.

Conversion rate. Current year conversions of proved undeveloped reserves to proved developed reserves, divided by beginning of the year proved undeveloped reserves (also commonly referred to in our industry as "*track record"*).

Costs incurred. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed reserves. Reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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.

Dry hole. An exploratory, development, or extension well that proves to be incapable of producing oil, gas, and/or NGLs in sufficient commercial quantities to justify completion, or upon completion, the economic operation of a well (also referred to as "*non-productive well"*).

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

FASB. Financial Accounting Standards Board.

Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and gas) rights.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

GAAP. Accounting principles generally accepted in the United States.

Gross acres or gross wells. Acres or wells in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses ("LOE"). The expenses incurred in the lifting of oil, gas, and/or NGLs from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet, used in reference to gas.

MMBbl. One million barrels, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet, used in reference to gas.

Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.

NGLs. The combination of ethane, propane, isobutane, normal butane, and natural gasoline that when removed from gas become liquid under various levels of higher pressure and lower temperature.

NYMEX WTI. New York Mercantile Exchange West Texas Intermediate, a common industry benchmark price for oil.

NYMEX Henry Hub ("HH"). New York Mercantile Exchange Henry Hub, a common industry benchmark price for gas.

OPEC+. The Organization of the Petroleum Exporting Countries ("*OPEC*") plus other non-OPEC oil producing countries.

OPIS. Oil Price Information Service, a common industry benchmark for NGL pricing at Mont Belvieu, Texas.

PV-10. PV-10 is a non-GAAP measure. The present value of estimated future revenue to be generated from the production of estimated proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This measure is presented because management believes it provides useful information to investors for analysis of the Company's fundamental business on a recurring basis.

Productive well. An exploratory, development, or extension well that is producing or is capable of commercial production of oil, gas, and/or NGLs.

Proved reserves. Those quantities of oil, gas, and NGLs which, that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Recompletion. The completion of an existing wellbore in a formation other than that in which the well has previously been completed.

Reserve life index. Expressed in years, represents the estimated proved reserves as of the end of the year divided by actual production for the preceding 12-month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil, gas, and/or associated liquid resources that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resource play. A term used to describe an accumulation of oil, gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has lower expected geological risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from oil, gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and gas property entitling the owner to shares of oil, gas, and NGL production free of costs of exploration, development, and production operations.

Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

SOFR. Secured Overnight Financing Rate.

Standardized measure of discounted future net cash flows. The discounted future net cash flows related to estimated proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, at a 10 percent annual discount rate. The information for this calculation is included in *Supplemental Oil and Gas Information (unaudited)* located in Part II, Item 8 of this report.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and NGLs regardless of whether such acreage contains estimated proved reserves.

Undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The applicable SEC definition of undeveloped reserves provides that undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

PART I

When we use the terms “SM Energy,” the “Company,” “we,” “us,” or “our,” we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business in the *Glossary* section of this report. Throughout this document we make statements and projections that address future expectations, possibilities, or events, all of which may be classified as “forward-looking statements.” Please refer Refer to the *Cautionary Information about Forward-Looking Statements* section of this report for an explanation of these types of statements and the associated risks and uncertainties.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas. Texas and Utah. SM Energy was founded in 1908, incorporated in Delaware in 1915, and our initial public offering of common stock was in 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol “SM.”

Our principal office is located at 1700 Lincoln Street, Suite 3200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our purpose is to make people’s lives better by responsibly producing energy supplies, contributing to domestic energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets by maintaining and optimizing our high-quality asset portfolio, generating cash flows, and maintaining a strong balance sheet. Our team executes this strategy by prioritizing safety, technological innovation, and stewardship of natural resources, all of which are integral to our corporate culture. Our near-term goals include continuing focusing on operational execution and successfully integrating the Uinta Basin assets; generating cash flows that enable us to return continue returning value to stockholders through fixed dividend payments, debt repayments, and our Stock Repurchase Program; and expanding our portfolio of top-tier economic drilling inventory through acquisition and exploration. Refer to *Significant Developments in 2024* below for the definitions of the Uinta Basin and the Stock Repurchase Program, as defined below, and fixed dividend payments, to *Outlook* for additional discussion of our 2025 strategy and by focusing on continued operational excellence. plans.

Our asset portfolio is comprised of high-quality assets in the Midland Basin of West Texas, and in the Maverick Basin of South Texas, that and the Uinta Basin of northeastern Utah, which we believe are capable of generating strong returns in the current macroeconomic environment and provide resilience to commodity price risk and volatility. We seek to maximize returns and increase the value of our top-tier assets through disciplined capital spending, strategic acquisitions, including the Uinta Basin Acquisition, and continued development and optimization of our existing assets. We believe that our high-quality assets facilitate a sustainable approach to prioritizing operational execution, maintaining a strong balance sheet, generating cash flows, returning capital to stockholders, and maintaining financial flexibility. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

We are committed to exceptional safety, health, and environmental stewardship; supporting the professional development of a diverse and thriving team of employees; building and maintaining partnerships with our stakeholders by investing in and connecting with the communities where we live and work; and transparency in reporting our progress in these areas. We have prioritized ESG initiatives by, among other things, integrating enhanced environmental and social programs throughout the organization and setting goals that include safety and spill metrics, minimizing flaring and reducing greenhouse gas (“GHG” or “GHGs”) emissions intensity, and maintaining low methane emissions intensity. Additionally, we are implementing have implemented systems and technologies to track ESG metrics to improve future reporting and performance and to increase employee awareness. We continue to evaluate new technologies to support our ESG initiatives. The Environmental, Social and Governance Committee of our Board of Directors oversees, among other things, the effectiveness of our ESG policies, programs and initiatives, monitors and responds to emerging trends, issues, and associated risks, and, together with management, reports to our Board of Directors regarding such matters. Further demonstrating our commitment to sustainable operations and environmental stewardship, compensation for our executives and eligible employees under our long-term incentive plan, and compensation for all employees under our short-term incentive plan is calculated based on, in part, certain Company-wide, performance-based metrics that include key financial, operational, environmental, health, and safety measures.

Significant Developments in 2023 2024

Return of Capital Program *Acquisition Activity*. In 2023, we continued to execute on our goal of sustainably returning capital to our stockholders through our Stock Repurchase Program and fixed quarterly dividend payments. Our Stock Repurchase Program commenced in September 2022, and originally authorized the repurchase of up to $500.0 million in aggregate value of our common stock through December 31, 2024 (“Stock Repurchase Program”). During the year ended December 31, 2023 On October 1, 2024, we repurchased acquired approximately 63,300 net acres of primarily proved oil and subsequently retired 6.9 million shares gas assets, and related supporting facilities located in Duchesne and Uintah counties, Utah, including approximately 103.2 MMBOE of our common stock at existing net proved reserves, for an unadjusted purchase price of $2.1 billion, establishing a cost of $228.0 million, excluding excise taxes, commissions, and fees. As of the filing of this report, $214.9 million remains available for repurchases of our outstanding common stock under the Stock Repurchase Program. During the year ended December 31, 2023, we paid dividends of $0.60 per share, an increase from $0.16 per share paid during the year ended December 31, 2022. Additionally, in November 2023, we announced a 20 percent increase to our fixed dividend to $0.72 per share annually, to be paid in quarterly increments of $0.18 per share, beginning new position in the first quarter of 2024. Please refer Uinta Basin in northeastern Utah (“Uinta Basin”). Our Uinta Basin position provides future development and exploration opportunities within multiple oil-rich intervals in the Lower Green River and Wasatch formations, and includes acreage with waxy crude and gas composition amenable to processing

for NGL extraction. Refer to *Note 3 17 – Equity Acquisitions* in Part II, Item 8 of this report for additional discussion. The information presented in this report regarding our Uinta Basin assets pertains to the fourth quarter of 2024 and does not represent the full-year 2024.

Acquisition Activity Senior Notes Activity. During 2024, we issued $750.0 million in aggregate principal amount of our 6.75% Senior Notes at par with a maturity date of August 1, 2029 (“2029 Senior Notes”) and $750.0 million in aggregate principal amount of our 7.0% Senior Notes at par with a maturity date of August 1, 2032 (“2032 Senior Notes”). During 2023, As a result of these issuances, we acquired approximately 20,000 received combined net acres proceeds of oil $1.5 billion after deducting fees of $23.0 million, which we used in part to fund the acquisition activity discussed above, and gas properties in Dawson and northern Martin counties, Texas. Additionally, in to redeem the Midland Basin, we added approximately 9,100 net acres through organic leasing activity, we completed an asset exchange, and we acquired additional working interests in certain wells. Please refer $349.1 million of aggregate principal amount outstanding of our 5.625% Senior Notes due June 1, 2025 (“2025 Senior Notes”). The redeemed 2025 Senior Notes were canceled upon settlement. Refer to *Note 16 5 – Acquisitions Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Reserves and Capital Investment. Our total estimated net proved reserves were 678.3 MMBOE as of December 31, 2024, an increase of 12 percent from 604.9 MMBOE as of December 31, 2023, which was an increase of 13 percent from 537.4 MMBOE as of December 31, 2022. This increase primarily consisted of the acquisition of 103.2 MMBOE of estimated net proved reserves in the Uinta Basin and revisions of previous estimates of 113.9 74.7 MMBOE related to infill reserves in both our South Texas and Midland Basin programs, programs. This increase was partially offset by 55.5 62.4 MMBOE of production during 2023. and 30.5 MMBOE of revisions of previous estimates related to the removal of certain net proved undeveloped reserve cases that are no longer expected to be developed within the five-year period from initial booking as a result of the reallocation of capital to include our Uinta Basin assets. Our proved reserve life index increased to remained flat at 10.9 years as of December 31, 2023 December 31, 2024, compared with 10.1 years as of December 31, 2022. Please refer and 2023. Refer to *Areas of Operation* and *Reserves* below for additional discussion regarding revisions of previous estimates due to infill, price, and performance revisions, the removal of certain changes in estimated net proved undeveloped reserve cases that are no longer within our development plan over the next five years, and additions from extensions and discoveries. reserves. Costs incurred increased 28 184 percent from 2022 2023 to $1.2 billion $3.5 billion in 2023. Please refer 2024. Refer to *Areas of Operation* below, and to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Return of Capital Program. In 2024, we continued to execute on our goal of sustainably returning capital to our stockholders through our fixed dividend payments and Stock Repurchase Program, as defined below. Our Board of Directors approved an increase to our fixed dividend to $0.80 per share annually, to be paid in quarterly increments of $0.20 per share, which commenced in the fourth quarter of 2024. During the year ended December 31, 2024, we paid dividends of $0.74 per share, an increase from $0.60 per share paid during the year ended December 31, 2023.

During the first half of 2024, we repurchased and subsequently retired 1.8 million shares of our common stock at a cost of $84.0 million, excluding excise taxes, commissions, and fees. In June 2024, our Board of Directors re-authorized the existing stock repurchase program to re-establish our authorization to repurchase up to $500.0 million in aggregate value of our common stock through December 31, 2027 (“Stock Repurchase Program”). As of December 31, 2024, $500.0 million remained available for repurchases of our outstanding common stock under the Stock Repurchase Program. Refer to *Note 3 – Equity* in Part II, Item 8 of this report for additional discussion.

Production, Pricing and Revenue, and Commodity Derivatives. Our average net daily equivalent production in 2023 2024 increased five 12 percent compared with 2022 2023 to 152.0 170.5 MBOE, consisting of 65.1 80.2 MBbl of oil, 362.7 374.3 MMcf of gas, and 26.4 27.9 MBbl of NGLs, as a result of an increased number of completions. completions, strong well performance, and production from our Uinta Basin assets during the fourth quarter of 2024. Oil production as a percentage of total production decreased increased to 47 percent in 2024 from 43 percent in 2023, from 45 percent in 2022, as a result of increased oil production from both our Midland Basin and South Texas assets, in addition to oil production from our South Texas assets becoming a higher percentage of total production in 2023. Uinta Basin assets.

Realized prices before the effect of net derivative settlements (“realized price” or “realized prices”) for oil and gas and NGLs decreased 19 percent, 61 two percent and 35 27 percent, respectively, for the year ended December 31, 2023 December 31, 2024, compared with 2022. As a result of decreased realized prices, oil, 2023. Realized price for NGLs remained flat for the year ended December 31, 2024, compared with 2023. Oil, gas, and NGL production revenue decreased 29 increased 13 percent to $2.4 billion $2.7 billion for the year ended December 31, 2023 December 31, 2024, compared with $3.3 $2.4 billion for 2022. 2023, primarily as a result of the timing of well completions, strong well performance, and production from our Uinta Basin assets. Oil production revenue was 77 82 percent and 68 77 percent of total production revenue for the years ended December 31, 2023 December 31, 2024, and 2022, 2023, respectively.

We recorded a net derivative gain gains of $50.0 million and $68.2 million for the year years ended December 31, 2023 December 31, 2024, compared to a net derivative loss of $374.0 million for the year ended December 31, 2022. and 2023, respectively. These amounts include a net derivative settlement gain gains of $68.7 million and $26.9 million for the year years ended December 31, 2023 December 31, 2024, and a net derivative settlement loss of $710.7 million for the year ended December 31, 2022. 2023, respectively.

Please refer Refer to *Areas of Operation* below and *Overview of the Company* in Part II, Item 7 of this report for additional discussion.

Outlook

Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets. We are focused Our 2025 strategy and operational plan seeks to deliver long-term profitability and value creation by:

- focusing on operational execution, maintaining successfully integrating our Uinta Basin assets, and expanding delivering low breakeven, high return wells across our portfolio quality by optimizing capital efficiency, demonstrating innovation and depth, and remaining a leader in stewardship;
- returning capital to stockholders by generating cash flows to support our increased fixed dividend payments, reduce debt, and return value through our Stock Repurchase Program Program; and fixed dividend, while maintaining a strong balance sheet.
- expanding our portfolio of top-tier economic drilling inventory through acquisition and exploration, and the application of advanced analytics, new technologies, and development optimization.

We expect our total 2024 2025 capital program to be between $1.16 billion and $1.20 billion approximately $1.3 billion, excluding acquisitions, which we expect to fund with cash flows from operations, and with any remaining cash on hand. needs being funded by borrowings under our revolving credit facility. We plan to focus our 2024 2025 capital program on highly economic oil development projects in both our Midland Basin, and South Texas, assets, including the assets we acquired during 2023. We expect to repurchase additional shares of our outstanding common stock through our Stock Repurchase Program during 2024, under which $214.9 million remains available for repurchases through December 31, 2024, as of the filing of this report. and Uinta Basin assets.

Areas of Operation

Area Map 1.24.24.jpg

(1) As of December 31, 2023.

Our 2023 operations were concentrated are conducted in the United States, with activity in the Midland Basin, and South Texas, and the Uinta Basin, as described below. The following table summarizes estimated net proved reserves, net production volumes, and costs incurred for the year ended December 31, 2023 December 31, 2024, for these areas:

	Midland Basin	Midland Basin	South Texas	Total (1)		Midland Basin	South Texas	Uinta Basin	Total (1)
Net proved reserves									
Oil (MMBbl)									
Oil (MMBbl)									
Oil (MMBbl)									
Gas (Bcf)									
NGLs (MMBbl)									
MMBOE (1)									
Relative percentage	Relative percentage	44 %	56 %	100 %	Relative percentage	34 %	51 %	15 %	100 %
Proved developed %	Proved developed %	62 %	52 %	56 %	Proved developed %	75 %	56 %	38 %	60 %
Net production volumes									
Oil (MMBbl)									
Oil (MMBbl)									
Oil (MMBbl)									
Gas (Bcf)									
NGLs (MMBbl)									
MMBOE (1)									
Avg. daily equivalents (MBOE/d) (1)									
Relative percentage	Relative percentage	50 %	50 %	100 %	Relative percentage	47 %	48 %	5 %	100 %
Costs incurred (in millions) (2) (3)									

(1) Amounts may not calculate due to rounding.

(2) Asset costs incurred do not sum to total costs incurred primarily due to corporate charges incurred on exploration activities and costs related to exploration efforts outside of our core areas of operation that are excluded from this table. For total costs incurred, please refer to *Costs Incurred* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

(3) Asset costs incurred include $2.1 billion related to acquisition costs, primarily related to the Uinta Basin Acquisition. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

Total estimated net proved reserves at December 31, 2023 December 31, 2024, increased 13 12 percent from December 31, 2022 December 31, 2023. Total net equivalent production increased five 12 percent for the year ended December 31, 2023 December 31, 2024, compared with 2022. 2023. Costs incurred for the year ended December 31, 2023 December 31, 2024, increased 28 184 percent compared with 2022, 2023, primarily as a result of increases an increase in capital activity related to the development of both our Midland Basin and South Texas assets, acquisitions acquisition of proved and unproved properties and leasing activity in the Midland Basin, and inflation.

Uinta Basin.

Midland Basin. Our Midland Basin assets, located in the Permian Basin in West Texas, are comprised of approximately 110,000 net acres, and include our RockStar assets in Howard and Martin counties, our Sweetie Peck assets in Upton and Midland counties, and our Klondike assets which we acquired in 2023, in Dawson and northern Martin counties ("Midland Basin"). In 2023, 2024, our drilling and completion activities were focused within on development optimization of our RockStar and Sweetie Peck assets, and we began drilling on delineation and development of our newly acquired Klondike acreage. assets. Our current Midland Basin position provides substantial future development opportunities within multiple oil-rich intervals, including the Spraberry, Wolfcamp, and Wolfcamp Woodford Barnett formations. We expect our 2024 2025 capital activity in the Midland Basin to be focused on highly economic oil development projects.

In 2023, 2024, costs incurred were $768.1 million totaled $720.9 million, and we averaged three four drilling rigs and one completion crew. We drilled 54 89 gross (37 net) wells, completed 64 gross (54 (73 net) wells and acquired additional working interests in five net completed 88 gross (73 net) wells, during the year ended December 31, 2023. As and as of December 31, 2023 December 31, 2024, 39 40 gross (29 net) wells had been drilled but not completed in our operated Midland Basin program. Net equivalent production for the year ended December 31, 2023 December 31, 2024, was 27.5 29.4 MMBOE, a seven percent decrease increase from 29.7 27.5 MMBOE for the year ended December 31, 2022 December 31, 2023. Estimated net proved reserves increased four decreased 14 percent to 230.5 MMBOE at December 31, 2024, from 268.5 MMBOE at December 31, 2023, . We removed 10.5

MMBOE of net proved undeveloped reserves that are no longer expected to be developed within the five-year period from 257.4 initial booking as a result of the reallocation of capital to include our Uinta Basin assets. Reserve reductions also included 29.4 MMBOE at December 31, 2022. Positive of production and 8.0 MMBOE of negative performance revisions. These decreases were partially offset by 8.2 MMBOE of additions from extensions and discoveries and 5.8 MMBOE of positive revisions of previous estimates primarily consisted of 43.4 MMBOE of infill and 21.3 MMBOE resulting from changes to decline curve estimates based on reservoir engineering analysis, partially offset by negative revisions of 18.2 MMBOE related to well performance and production of 27.5 MMBOE. infill.

South Texas. Our South Texas assets are comprised of approximately 155,000 net acres located in Dimmit and Webb counties, Texas ("South Texas"). In 2023, 2024, our operations in South Texas were focused on development and further delineation of the Austin Chalk formation, and on production from both the Austin Chalk formation and the Eagle Ford shale formation, and further development of the Austin Chalk formation. Our overlapping acreage position in the Maverick Basin in South Texas covers a significant portion of the western Eagle Ford shale and Austin Chalk formations ("Maverick Basin") and includes acreage across the oil, gas-condensate, and dry gas windows with gas composition amenable to processing for NGL extraction. We expect our 2024 2025 capital activity in South Texas to be focused primarily on developing the Austin Chalk formation.

In 2023, 2024, costs incurred were $423.5 million totaled $478.3 million, and we averaged two drilling rigs and one completion crew. We drilled 46 52 gross (46 (52 net) wells and completed 38 54 gross (37 (54 net) wells, and as of December 31, 2023 December 31, 2024, 37 35 gross (37 (35 net) wells had been drilled but not completed in our operated South Texas program. Net equivalent production for the year ended December 31, 2023 December 31, 2024, was 28.0 29.6 MMBOE, a 20 six percent increase from 23.2 28.0 MMBOE for the year ended December 31, 2022 December 31, 2023. Estimated net proved reserves increased 20 three percent to 347.9 MMBOE at December 31, 2024, from 336.4 MMBOE at December 31, 2023, from 280.0 MMBOE at December 31, 2022. Positive revisions of previous estimates primarily consisted of 70.4 69.0 MMBOE of infill, and 44.0 MMBOE of performance revisions resulting from changes to decline curve estimates based on reservoir engineering analysis. Additions of 30.1 MMBOE were the result of continued success in our development of the Austin Chalk formation. These increases were partially offset by production 29.6 MMBOE of 28.0 MMBOE, negative price revisions of 24.5 MMBOE, and negative revisions of 9.9 MMBOE related to well performance. As a result of revising our development plan, partially in response to decreased benchmark gas prices and certain lease obligations, we production. We removed 25.8 20.1 MMBOE of net proved undeveloped reserves that were are no longer expected to be developed within the five-year period from initial booking as a result of the reallocation of capital to include our Uinta Basin assets. Reserve reductions also included 10.6 MMBOE due to decreases in gas prices.

Uinta Basin. Our Uinta Basin assets, which we acquired during the fourth quarter of 2024, are comprised of approximately 63,300 net acres located in northeastern Utah. During the fourth quarter of 2024, our operations focused on delineation and development. Our Uinta Basin position provides substantial future development and exploration opportunities within multiple oil-rich intervals in the Lower Green River and Wasatch formations, and includes acreage with waxy crude and gas composition amenable to processing for NGL extraction. We expect our 2025 capital activity in the Uinta Basin to be focused on highly economic oil development projects.

During the fourth quarter of 2024, costs incurred totaled $2.3 billion, of which, over $2.1 billion related to acquisition costs, and we averaged three drilling rigs and one completion crew. We drilled 19 gross (15 net) wells and completed 11 gross (eight net) wells, and as of December 31, 2024, 48 gross (38 net) wells had been drilled but not completed in our five-year development plan. These operated Uinta Basin program. During the year ended December 31, 2024, we acquired 103.2 MMBOE of existing net proved undeveloped reserves primarily related to our Eagle Ford assets in the Uinta Basin, and were replaced with certain infill revisions to net equivalent production was 3.3 MMBOE, resulting in 99.9 MMBOE of estimated net proved undeveloped reserves associated with different locations that were added remaining at December 31, 2024. Refer to our five-year development plan. Additionally, infill revisions replaced converted net proved undeveloped reserves.*Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

Office Space. As of December 31, 2023 December 31, 2024, we leased and owned office space as summarized in the table below:

	Approximate Square Footage Leased	**Approximate Square Footage Leased**	**Approximate Square Footage Owned**	**Approximate Square Footage Leased**	**Approximate Square Footage Owned**
Corporate - Denver, CO					
Midland, TX					
Houston, TX and Catarina, TX, respectively					
Roosevelt, UT					
Total					

Reserves

Reserve estimates are inherently imprecise. Estimates for new discoveries and undeveloped locations are considered more imprecise than reserve estimates for producing oil and gas properties. Accordingly, we expect these estimates to change as new information becomes available. The table below presents the standardized measure of discounted future net cash flows and PV-10. PV-10 is a non-GAAP financial measure that is reconciled to the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure. PV-10 does not include the effects of income taxes on future net revenues. Neither the standardized measure of discounted future net cash flows nor PV-10 represents the fair market value of our oil and gas properties. We and others in the oil and gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held before consideration of tax characteristics specific to individual entities. Please refer Refer to the *Glossary* section of this report for additional information regarding these measures and refer to the reconciliation of the standardized measure of discounted future net cash flows to PV-10 set forth below. The actual quantities and present value of our estimated net proved reserves may be more or less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year. The table below should be read along with *Risk Factors* in Part I, Item 1A of this report.

The following table summarizes estimated net proved reserves, the standardized measure of discounted future net cash flows (GAAP), PV-10 (non-GAAP), the prices used in the calculation of net proved reserves estimates, and reserve life index as of December 31, 2023 December 31, 2024, 2022, 2023, and 2021: 2022:

	As of December 31,		
	2023	**2022**	**2021**
	2024	**2023**	**2022**
Net reserve volumes:			

Proved developed

Proved developed

Proved developed

Oil (MMBbl)

Oil (MMBbl)

Oil (MMBbl)

Gas (Bcf)

NGLs (MMBbl)

MMBOE (1)

Proved undeveloped

Oil (MMBbl)

Oil (MMBbl)

Oil (MMBbl)

Gas (Bcf)

NGLs (MMBbl)

MMBOE (1)

Total proved (1)

Oil (MMBbl)

Oil (MMBbl)

Oil (MMBbl)

Gas (Bcf)

NGLs (MMBbl)

MMBOE

Net proved developed reserves percentage	Net proved developed reserves percentage	56 %	59 %	61 %	Net proved developed reserves percentage	60 %	56 %	59 %
Net proved undeveloped reserves percentage	Net proved undeveloped reserves percentage	44 %	41 %	39 %	Net proved undeveloped reserves percentage	40 %	44 %	41 %

Reserve data (in millions):

Reserve data (in millions):

Reserve data (in millions):

Standardized measure of discounted future net cash flows (GAAP)

Standardized measure of discounted future net cash flows (GAAP)

Standardized measure of discounted future net cash flows (GAAP)

PV-10 (non-GAAP):

Proved developed PV-10

Proved developed PV-10

Proved developed PV-10

Proved undeveloped PV-10

Total proved PV-10 (non-GAAP)

12-month trailing average prices: (2)

12-month trailing average prices: (2)

12-month trailing average prices: (2)

Oil (per Bbl)

Oil (per Bbl)

Oil (per Bbl)

Gas (per MMBtu)

NGLs (per Bbl)

Reserve life index (years) (3)

Reserve life index (years) (3)

Reserve life index (years) (3)

Reserve life index (years) (3) (4)

Reserve life index (years) (3) (4)

Reserve life index (years) (3) (4)

(1) Amounts may not calculate due to rounding.

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(2) The prices used in the calculation of proved reserve estimates reflect the unweighted arithmetic average of the first-day-of-the-month price of each month within the trailing 12-month period in accordance with SEC rules. We then adjust these prices to reflect appropriate quality and location differentials over the period in estimating our net proved reserves.

(3) Please refer Refer to the reserve life index term in the *Glossary* section of this report for information describing a description of how this metric is calculated.

(4) As of December 31, 2024, the reserve life index includes production from our Uinta Basin assets and reflects activity occurring after the closing of the Uinta Basin Acquisition on October 1, 2024. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 (non-GAAP) of total estimated net proved reserves. Please refer Refer to the *Glossary* section of this report for the definitions of standardized measure of discounted future net cash flows and PV-10.

	As of December 31,		
	2023	2022	2021
	2024	2023	2022
	(in millions)		
	(in millions)		
	(in millions)		
Standardized measure of discounted future net cash flows (GAAP)			
Add: 10 percent annual discount, net of income taxes			
Add: future undiscounted income taxes			
Pre-tax undiscounted future net cash flows			
Less: 10 percent annual discount without tax effect			
PV-10 (non-GAAP)			

Proved Undeveloped Reserves

Proved undeveloped reserves include those reserves that are expected to be recovered from future wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of economic producibility when drilled or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. As of December 31, 2023 December 31, 2024, we did not have any net proved undeveloped reserves that had been on our books in excess of five years, and substantially all of our net proved undeveloped reserves were on acreage that was not expected to expire, or that was expected to be held through renewal, before the targeted completion date.

For proved undeveloped locations that are more than one development spacing area from developed producing locations, we utilized reliable geologic and engineering technology when booking estimated net proved undeveloped reserves. Of the 263.6 274.3 MMBOE of total net proved undeveloped reserves as of December 31, 2023 December 31, 2024, approximately 36.8 26.4 MMBOE, 63.0 MMBOE, and 18.7 MMBOE of net proved undeveloped reserves in the Midland Basin, and 87.3 MMBOE of net proved undeveloped reserves in South Texas, and the Uinta Basin, respectively, were offset by more than one development spacing area from the nearest proved developed producing location. We incorporated public and proprietary data from multiple sources to establish geologic continuity of each formation and their producing properties. This included seismic data and interpretations (3-D and micro seismic), open hole log information (both vertically and horizontally collected) and petrophysical analysis of that log data, mud logs, gas sample analysis, measurements of total organic content, thermal maturity, test production, fluid properties, and core data as well as statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas where both established geologic consistency and sufficient statistical performance data could be demonstrated to provide reasonably certain results.

As of December 31, 2023 December 31, 2024, estimated net proved undeveloped reserves increased 44.1 10.7 MMBOE, or 20 four percent, compared with December 31, 2022 December 31, 2023. The following table provides a reconciliation of our net proved undeveloped reserves for the year ended December 31, 2023 December 31, 2024:

	Total (MMBOE)
Total net proved undeveloped reserves:	
Beginning of year	219.6 263.6
Conversions to proved developed	(86.9)
Purchases of minerals in place	62.3
Revisions of previous estimates	98.8
Conversions to proved developed	(43.1) 58.0
Removed for five-year rule	(30.8) (30.5)
Additions from extensions and discoveries	22.7 7.8
(5.3)	
Purchases of minerals in place	1.8
End of year(1)	263.6 274.3

(1) Amount may not calculate due to rounding.

Revisions of previous estimates. During 2023, revisions of previous estimates totaled 98.8 MMBOE. Positive revisions consisted of 103.8 MMBOE of infill reserves, of which 60.5 MMBOE and 43.3 MMBOE of estimated net proved undeveloped reserves were attributable to our South Texas and Midland Basin programs, respectively, and 13.3 MMBOE of performance revisions resulted from changes to decline curve estimates based on reservoir engineering analysis. Negative revisions consisted of 14.2 MMBOE that resulted from well performance related to infill development, and price revisions of 4.0 MMBOE that resulted primarily from decreases in benchmark gas and NGL prices.

Conversions to proved developed. Our 2023 2024 conversion rate was 20 33 percent and resulted primarily resulted from the development of proved reserves in our Midland Basin program and in our Austin Chalk assets in our South Texas program. During 2023, 2024, we incurred $740.2 $872.9 million on projects with reserves booked as proved undeveloped at the end of 2022, 2023, of which $515.9 $685.6 million was spent on converting net proved undeveloped reserves to proved developed reserves by December 31, 2023 December 31, 2024. During the fourth quarter of 2024, we incurred $84.4 million on projects with reserves booked as proved undeveloped as of December 31, 2024, that were acquired as

part of the Uinta Basin Acquisition. At December 31, 2023 December 31, 2024, drilled but not completed wells represented 41.2 55.9 MMBOE of total estimated net proved undeveloped reserves. We expect to incur $212.6 $423.1 million of additional capital expenditures in completing these drilled but not completed wells, and we expect all estimated net proved undeveloped reserves to be converted to proved developed reserves within five years from their initial booking as net proved undeveloped reserves.

Purchases of minerals in place. During 2024, we completed the Uinta Basin Acquisition and acquired 62.3 MMBOE of net proved undeveloped reserves in the Uinta Basin. Refer to *Note 17 – Acquisitions* in Part II Item 8 of this report for additional information and the definition of the Uinta Basin Acquisition.

Revisions of previous estimates. During 2024, revisions of previous estimates totaled 58.0 MMBOE. Positive revisions consisted of 63.1 MMBOE of infill reserves, of which 57.8 MMBOE and 5.3 MMBOE of estimated net proved undeveloped reserves were attributable to our South Texas and Midland Basin programs, respectively. Negative revisions consisted of 2.6 MMBOE related to price revisions as a result of a decrease in gas prices and 2.5 MMBOE that resulted from well performance related to infill development.

Removed for five-year rule. As a result of our testing and delineation efforts in 2023, 2024, and the reallocation of capital to include our Uinta Basin assets, we revised certain aspects of our future development plan to focus on maximizing returns and the value of our assets. We removed 30.8 30.5 MMBOE of estimated net proved undeveloped reserves that are no longer expected to be developed within the five-year period from initial booking and reclassified these locations to unproved reserve categories, based on development schedule revisions made partially in response to decreased benchmark gas prices of which 20.1 MMBOE and certain lease obligations. Of the 30.8 MMBOE, 25.8 MMBOE primarily related to our Eagle Ford assets in our South Texas program, and 5.0 10.5 MMBOE related to our South Texas and Midland Basin program. programs, respectively.

Additions from extensions and discoveries. During 2023, 2024, we added 22.7 7.8 MMBOE of estimated net proved undeveloped reserves, of which 21.9 6.0 MMBOE were in the Midland Basin, and resulted from further development of our assets. The remaining 1.9 MMBOE of additions were in South Texas, and resulted from extensions from our continued success in delineating the Austin Chalk formation.

As of December 31, 2023 December 31, 2024, estimated future development costs relating to our net proved undeveloped reserves totaled $2.8 billion, and we expect to incur approximately $860.6 million $1.0 billion, $585.6 million $647.3 million, and $555.7 million $590.5 million in 2024, 2025, 2026, and 2026, 2027, respectively.

Internal Controls Over Proved Reserves Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC's regulations. Our process for managing and monitoring our proved reserves is delegated to our corporate reserves Corporate Engineering group and is this year was coordinated by our Corporate Engineering Manager, Business Development Director, subject to the oversight of our management and the Audit Committee of our Board of Directors ("Audit Committee"), as discussed below. Our Corporate Engineering Manager Business Development Director has worked in the energy industry since 2008 1988 and has been employed by the Company since 2010. 2000. He holds a Bachelor of Science degree in Petroleum Engineering from Montana Technological University and is a Registered Professional Petroleum Engineer in the states of Texas, Wyoming, and Montana. He is also a member of the Society of Petroleum Engineers. Technical, geological, and engineering reviews of our assets are performed throughout the year by our staff. Data obtained from these reviews, in conjunction with economic data and our ownership information, is used in making a determination of estimated net proved reserve quantities. Our asset teams' engineering technical staff do not report directly to our Corporate Engineering Manager; Business Development Director; they report to either their respective asset technical managers or directly to the Senior Vice President of Exploration, Development and EHS. regional vice president or senior vice president. This design is intended to promote objective and independent analysis within our asset teams in the proved reserves estimation process.

Third-party Reserves Audit

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world since 1937. Ryder Scott performed an independent audit using its own engineering assumptions, but with economic and ownership data we provided. Ryder Scott audits a minimum of 80 percent of our total calculated proved reserve PV-10. In the aggregate, the proved reserve amounts of our audited properties determined by Ryder Scott are required, per our policy, to be within 10 percent of our proved reserve amounts for the total Company, as well as for each respective major asset. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is a Senior Vice President who received a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002. She is a registered Professional Engineer in the State of Texas and a member of the Society of Petroleum Engineers. The 2023 2024 Ryder Scott audit report is included as Exhibit 99.1.

In addition to a third-party audit, our reserves are reviewed by our management with the Audit Committee. Our management, which includes our President and Chief Executive Officer, Executive Vice President and Chief Financial Officer, and Senior Executive Vice President of Exploration, Development and EHS, Chief Operating Officer, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews a summary of the final reserves estimate in conjunction with Ryder Scott's results and also meets with Ryder Scott representatives, separate from our management, from time to time to discuss processes and findings.

Production

The following table summarizes our net production volumes and realized prices for oil, gas, and NGLs produced and sold during the periods presented, and related production expense on a per BOE basis:

	For the Years Ended December 31,

		2023	2022	2021				
		2024	2023	2022				
Net production volumes								
Oil (MMBbl)								
Oil (MMBbl)								
Oil (MMBbl)		23.8	24.0	27.9		29.4	23.8	24.0
Gas (Bcf)	Gas (Bcf)	132.4	125.9	108.4	Gas (Bcf)	137.0	132.4	125.9
NGLs (MMBbl)								
Equivalent (MMBOE) (1)	Equivalent (MMBOE) (1)	55.5	53.0	51.4	Equivalent (MMBOE) (1)	62.4	55.5	53.0
Midland Basin net production volumes (2)								
Oil (MMBbl)								
Oil (MMBbl)								
Oil (MMBbl)								
Gas (Bcf)								
NGLs (MMBbl)								
Equivalent (MMBOE) (1)								
Maverick Basin net production volumes (2)								
Oil (MMBbl)								
Oil (MMBbl)								
Oil (MMBbl)		6.2	4.8	2.7		7.4	6.2	4.8
Gas (Bcf)	Gas (Bcf)	72.5	62.4	52.8	Gas (Bcf)	72.2	72.5	62.4
NGLs (MMBbl)								
Equivalent (MMBOE) (1)	Equivalent (MMBOE) (1)	27.9	23.2	16.9	Equivalent (MMBOE) (1)	29.6	27.9	23.2
Uinta Basin net production volumes (3)								
Oil (MMBbl)								
Oil (MMBbl)								
Oil (MMBbl)		2.9	—					
Gas (Bcf)		2.7	—					
NGLs (MMBbl)								
Equivalent (MMBOE) (1)		3.3	—					
Realized price								
Oil (per Bbl)								
Oil (per Bbl)								
Oil (per Bbl)								
Gas (per Mcf)								
NGLs (per Bbl)								
Per BOE								
Production expense per BOE								
Lease operating expense								
Lease operating expense								
Lease operating expense								
Transportation costs								
Production taxes								
Ad valorem tax expense								

(1) Amounts may not calculate due to rounding.

(2) For each of the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, total estimated net proved reserves attributed to our Midland Basin field and our Maverick Basin field each exceeded 15 percent of our total estimated net proved reserves expressed on an equivalent basis.

(3) For the year ended December 31, 2024, total estimated net proved reserves attributed to our Uinta Basin field represented 15 percent of our total estimated net proved reserves expressed on an equivalent basis.

Productive Wells

As of December 31, 2023 December 31, 2024, we had working interests in 898 1,262 gross (795 (950 net) productive oil wells and 528 566 gross (494 (530 net) productive gas wells. Productive wells are wells producing in commercial quantities or wells capable of commercial production that are temporarily shut-in. Multiple completions in the same wellbore are counted as one well, and as of December 31, 2023 December 31, 2024, two of these wells had multiple completions. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil when it first commenced production, but such designation may not be indicative of current or future production composition.

Drilling and Completion Activity

All of our drilling and completion activities are conducted by independent contractors using equipment they own and operate. The following table summarizes the number of operated and outside-operated wells drilled and completed or recompleted on our properties in 2024, 2023, 2022, and 2021, 2022, excluding non-consented projects, active injector wells, saltwater disposal wells, or wells in which we own only a royalty interest:

		For the Years Ended December 31,											
		2023		2022		2021							
		2024		2023		2022							
	Gross	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells													
Oil													
Oil													
Oil													
Gas													
Non-productive													
	95												
	136												
Exploratory wells													
Oil													
Oil													
Oil													
Gas													
Non-productive (1)													
	11												
	17												
Total													

Note: The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated.

(1) For each of the year years ended December 31, 2023 December 31, 2024, and 2023, one gross (one net) well was unsuccessful due to technical issues during the drilling phase and was not included in the drilled or completed well counts.

In addition to the wells completed in 2023 2024 (included in the table above), we were actively participating in the drilling of seven 27 gross (seven (20 net) wells and had 81 121 gross (70 (103 net) drilled but not completed wells as of January 31, 2024 January 31, 2025. Drilled but not completed wells as of January 31, 2024 January 31, 2025, represent wells that were being completed or were waiting on completion. The drilled but not completed well count as of January 31, 2024 January 31, 2025, includes nine gross (nine net) wells that were not included in our five-year development plan as of December 31, 2023 December 31, 2024, eight of which are in the Eagle Ford shale.

Title to Properties

As of December 31, 2023 December 31, 2024, over approximately 98 percent and 97 percent of our Texas and Utah operated oil and gas producing assets, are respectively, were located on private lands, are held pursuant to oil and gas leases from private mineral owners, and are were not located on federal lands or leased from the federal government. The remainder of our operated oil and gas producing assets in Texas are located on Texas state lands, and the remainder of our operated oil and gas producing assets in Utah are located on federal, state or tribal lands. We have obtained title opinions or have conducted other title review on substantially all of our producing properties and believe we have satisfactory title to such properties. We obtain new or updated title opinions prior to commencing initial drilling operations on the properties that we operate. Most of our producing properties are subject to mortgages securing indebtedness under our Credit Agreement, as defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report, royalty and overriding royalty interests, liens for current taxes, and other ordinary course burdens that we believe do not materially interfere with the development of such properties. We typically perform title investigations in accordance with standards generally accepted in the oil and gas industry before acquiring developed and undeveloped leasehold acreage.

Acreage

The following table sets forth the number of gross and net surface acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes that we held as of December 31, 2023 December 31, 2024:

	Developed Acres (1)		Developed Acres (1)		Undeveloped Acres (2)(3)		Total		Developed Acres (1)		Undeveloped Acres (2)(3)		Total	
	Gross	Gross	Net	Gross	Net	Gross	Net		Gross	Net	Gross	Net	Gross	Net
Midland Basin:														
RockStar														
RockStar														
RockStar														
Sweetie Peck														
Klondike														
Midland Basin Total (4)														
South Texas														
Uinta Basin														
Other (5)														
Total														

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations but has been included only as developed acreage in the table above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

(3) As of February 8, 2024 January 31, 2025, 2,077, 7,946, 6,299, 46,663, and 12,131 640 net acres of our undeveloped acreage is scheduled to expire by December 31, 2024 December 31, 2025, 2025, 2026, and 2026, 2027, respectively, unless production is established, or we take other action to extend the terms of the applicable leases. leases (a majority of this acreage is included in Other). Certain of our acreage, primarily in South Texas, is subject to lease consolidation agreements containing drilling, completion, and other obligations that we currently intend expect to satisfy. Failure to meet these obligations results in payments to lessors, or termination of the lease consolidation agreements, which could result in additional future lease expirations if continuous development obligations required by individual leases are not met.

(4) As of December 31, 2023 December 31, 2024, total Midland Basin acreage excludes 1,213 1,050 net acres associated with drill-to-earn opportunities that we intend to pursue.

(5) Includes other non-core acreage located in Colorado, Louisiana, Montana, North Dakota, Texas, Utah, and Wyoming.

Delivery Commitments

For gathering, processing, transportation throughput, and information about delivery commitments, please refer to *Delivery Commitments* within *Note 6 – Commitments and Contingencies* in Part II, Item 8 of this report.

Major Customers

For major customers and entities under common control that accounted for 10 percent or more of our total oil, gas, and NGL production revenue for at least one of the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, please 2022, refer to *Concentration of Credit Risk and Major Customers* within *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report.

Human Capital

Our Company culture recognizes our employees as our most valuable assets, encourages personal and professional development, promotes innovation and leadership among all employees and, in turn, supports our efforts to attract and retain talent. Through our culture, we promote:

- integrity and ethical behavior in the conduct of our business;
- environmental, health, and safety priorities;
- prioritizing the success of others and the team;
- collaboration and openness to new ideas and technologies that serve business improvement;
- support for team members' professional and personal development; and
- support for the communities where we live and work.

The core values of integrity and ethical behavior are the pillars of our culture, and all employees are responsible for upholding Company-wide standards and values. We have policies designed to promote ethical conduct and integrity, which employees are required to read and acknowledge on an annual basis. The health and safety of our employees and contractors is our highest priority. We strive to achieve performance excellence in environmental, health, and safety management, and compensation of all employees is tied to annual environmental, health, and safety performance goals.

Personal and professional development is an important part of our culture and is employee driven, manager facilitated, and organizationally supported. Employees are routinely provided training opportunities to develop skills in leadership, safety, and technical acumen, which help strengthen our efforts to conduct business with high ethical standards. During 2023, 2024, many of our employees participated in two four leadership and talent development programs that included more than 4,300 7,000 hours of aggregate training, exclusive of safety and other specialized technical training. In 2024, we were honored with two distinguished Leadership Development awards from the Brandon Hall Group. The Gold Award recognized our innovative approach to building competencies and skills, while the Bronze Award celebrated overall excellence in leadership development. These accolades underscore our commitment to cultivating a thriving corporate culture and strong leadership values.

We measure employee engagement and satisfaction through periodic surveys, administered by an independent third-party vendor.

We are proud of our many outstanding employees who invest their time, talents, and financial resources in their communities. Our annual charitable giving program includes a monetary match of our employees' personal contributions to qualified organizations and up to 12 hours per employee of Company-granted time to volunteer in the communities where we live and work.

We strive to provide competitive, performance-based compensation and benefits to our employees, including market-competitive pay, short-term and long-term incentive compensation plans, an employee stock purchase program, and various healthcare, retirement, and other benefit packages such as a hybrid work environment that is guided by each employee's job function and responsibilities. Compensation for our executives and employees under our short-term and long-term incentive plans is determined based on individual performance and Company performance with respect to qualitative and quantitative metrics that include environmental, health, and safety measures. The Compensation Committee of our Board of Directors oversees our compensation programs and regularly modifies reviews program design to incentivize achievement of our corporate strategy and the matters of importance to our stakeholders. Significant planning for succession of key personnel is performed each year, or more frequently as deemed necessary by management.

As of February 8, 2024 January 31, 2025, we had 544 663 full-time employees, none of whom were subject to a collective bargaining agreement. We are committed to diversity at all levels of our organization, and we strive to provide equal employment opportunities to all employees and job applicants. We regularly perform internal analyses of our workforce demographics, and, at times, we retain a third party to conduct discrimination and pay equity testing. No discriminatory practices have been identified and no evidence of discrimination or pay inequity has been found. Additionally, we have established procedures and controls designed to support our objective of remaining, at all times, in material compliance with applicable federal, state, tribal, and local laws and governmental regulations.

The following charts present certain Board of Directors and workforce metrics as of February 8, 2024:

Board of Directors Diversity	Officer Diversity (1)	Employee Diversity

4345 4346 7146825587001

Note: Ethnic diversity data is determined under guidelines set forth by the United States Equal Employment Opportunity Commission and includes the following categories: American Indian or Alaska Native, Asian, Black or African American, Hispanic or Latino, or the combination of two or more races (not Hispanic or Latino).

(1) Includes officers at the level of Vice President and above.

Seasonality

The price of crude oil is primarily driven by global socioeconomic and geopolitical factors and is less affected by seasonal fluctuations; however, demand for energy is generally higher in the winter and in the summer driving season. The demand and price for gas generally increases during winter months and decreases during summer months. To lessen the effect of seasonal gas demand and price fluctuations, pipelines, utilities, local distribution companies, and industrial users regularly utilize gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can divert gas that is traditionally placed into storage which, in turn, may increase the typical winter seasonal price. Seasonal anomalies, such as mild or extreme winters sometimes lessen or exacerbate these fluctuations.

Certain of our drilling, completion, and other operational activities are also subject to seasonal limitations. Seasonal weather conditions, government or tribal regulations, and lease stipulations could adversely affect our ability to conduct drilling activities in some of the areas where we operate. Please refer Refer to *Risk Factors* in Part I, Item 1A of this report for additional discussion.

Competition

The oil and gas industry is highly competitive, particularly with respect to acquiring prospective oil and gas properties. We believe our acreage positions provide a foundation for development activities that we expect to fuel our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from many major and independent oil and gas companies, which in some cases have larger technical teams and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and gas reserves, but also have gathering, processing or refining operations, market refined products, provide, dispose of and transport fresh and produced water, own drilling rigs or production equipment, or generate electricity, all of which, individually or in the aggregate, could provide such companies with a competitive advantage.

We also compete with other oil and gas companies in securing drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells, as well as for the gathering, transporting, and processing of oil, gas, NGLs, and water. Consequently, we may face shortages, delays, or increased costs in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including renewable energy sources such as solar and wind-generated energy, and other fossil fuels such as coal. Competitive conditions may be affected by future energy, environmental, climate-related, financial, or other policies, legislation, and regulations.

In addition, we compete for professionals in our workforce, including specialized roles in the oil and gas industry such as geologists, geophysicists, engineers, and others. Throughout the general labor market, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to the evolving demographics of our industry. The oil and gas industry is not insulated from the competition for quality people, and we must compete effectively to be successful. Please refer Refer to *Human Capital* above and *Risk Factors* in Part I, Item 1A of this report for additional discussion.

Government Regulations

Although our regulatory compliance obligations are mitigated by the fact that we do not own or operate oil and gas properties on federal lands, nearly every aspect of our Our business is subject to expansive federal, state, tribal, and local laws and governmental regulations. These laws and regulations frequently change in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential to increase our cost of conducting business and consequently could affect our profitability.

Energy Regulations

Both Texas the state where we conduct operations and lease or own nearly all of our oil and gas assets, has Utah have adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations requiring permits for the drilling of wells, imposing bond requirements in order to drill or operate wells, governing the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to Texas and Utah conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, both Texas and Utah conservation laws establish maximum rates of production from oil and gas wells, generally limit or prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

A portion of our acreage in the Uinta Basin is subject to tribal laws, ordinances, rules, and regulations. In addition to potential regulation by federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations may apply to lessees, operators, third party contractors, and other parties on tribal or allotted Indian lands. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, and tribal employment and contractor preferences, among other matters. Further, lessees and operators on Indian lands may be subject to the jurisdiction of tribal courts, unless there is a specific waiver of sovereign immunity by the relevant tribe allowing resolution of disputes between the tribe and those lessees or operators to occur in federal or state court.

A portion of our acreage in the Uinta Basin is on federal lands subject to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders that are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and must comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may suspend or terminate our operations on federal leases.

Our sales of gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for gas production.

Environmental, Health, and Safety Matters

General. Our operations are subject to stringent and complex federal, state, tribal, and local laws and regulations governing protection of the environment and worker health and safety, as well as the discharge of materials and emissions into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities, and concentration of various substances and emissions that may be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as closing pits and plugging abandoned wells.

These laws, rules, and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of conducting business and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes may result in more stringent, or different permitting, waste handling, disposal, and cleanup requirements for the oil and gas industry and could have a significant impact on our operating costs.

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

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency ("EPA"), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water, and most of the other wastes associated with the exploration, development, and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation, and Liability Act. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release or threatened release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of, or transported, a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of environmental investigation and certain health studies. In addition, it is not uncommon for third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and gas exploration and production for many years. CERCLA excludes petroleum and natural gas from its definition of hazardous substances, and although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances or wastes may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for 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 hydrocarbons were not under our control. These properties, and the substances disposed or released on them, may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, pay fines, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act ("Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and waters of the applicable states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, or analogous state agencies. This includes the discharge of certain storm water without a permit which requires periodic monitoring and sampling. In addition, the Clean Water Act regulates wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process and discharged to publicly-owned wastewater treatment facilities. The Clean Water Act also prohibits discharge of dredged or fill material into waters of the United States, including wetlands, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers, or a state, if the state has assumed authority to issue such permits. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 ("OPA") addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act ("CAA") and comparable state laws and regulations regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements, such as requirements for emission reduction, capture and control. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of hazardous air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. Please refer Refer to the *Environmental* section in Part II, Item 7 of this report for additional information about the regulation of air emissions from the oil and gas sector.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other GHGs endanger public health and welfare, and as a result, began adopting and implementing a comprehensive suite of regulations to restrict emissions of GHGs under existing provisions of the CAA. While President Trump's administration took steps Current and future legislative and regulatory initiatives related to rescind or review many climate change and emissions of these regulations, GHGs could have an adverse effect on our operations and the demand for oil and gas. President Biden's administration has actively been reviewing those actions and taking took steps to strengthen and expand the many of these regulations, specifically targeting, among other things, the regulation of methane emissions from the oil and gas sector. Legislative President Trump's administration may take steps to rescind or review many of these regulations; however, any future actions may be subject to legal challenges and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. Please refer cannot be predicted with accuracy at this time. Refer to *Risk Factors - Risks Related to Oil and Gas Operations and the Industry Government Regulations - Legislative and regulatory initiatives and litigation related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation, capital, and related expenses* in Part I, Item 1A of this report. Meteorological or extreme weather events (whether or not related to climate change), pose additional risks to our operations, which and in the past, have included resulted in temporary shut-ins of certain wells and temporary capacity constraints at third-party purchasers impacting their ability to take delivery of our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts on protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on these species. It is also possible that a federal or state agency could order a complete halt to activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling, completion, and production activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice used to stimulate production of hydrocarbons from tight shale formations. We routinely utilize hydraulic fracturing techniques in most of our drilling and completion programs. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, even on private lands, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids, including saltwater disposal fluids, into below-ground formations that may adversely affect drinking water sources.

Increased regulation and scrutiny on oil and gas activities involving hydraulic fracturing techniques could potentially lead to a decrease in the completion of new oil and gas wells, an increase in compliance costs, delays, and changes in federal income tax laws, all of which could adversely affect our financial position, results of operations, and cash flows. As new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local levels, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements, which could result in additional permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and gas that we are ultimately able to produce from our reserves.

We believe the trend in local and state environmental legislation and regulation may continue toward stricter standards, while the outlook regarding federal environmental legislation and regulation will continue toward stricter standards, particularly is uncertain under President Biden's the Trump administration. While we believe we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot give any assurance that we will not be adversely affected in the future.

Environmental, Health, and Safety Initiatives. We are committed to exceptional safety, health, and environmental stewardship; making a positive difference in the communities where we live and work; and transparency in reporting our progress in these areas. We

set annual goals for our safety, health, and environmental program focused on minimizing the number of safety related incidents and the number and impact of spills of produced fluids. In addition, we set annual goals for GHG emissions intensity and methane emissions as a percentage of total methane produced, and as part of our current ESG initiatives, we have set goals that include minimizing flaring, reducing GHG emissions intensity, and maintaining low methane emissions intensity. We also periodically conduct audits of our operations to ensure regulatory compliance, and we strive to provide appropriate training for our employees. Minimizing air emissions as a result of leaks, venting, or flaring of gas during operations has become a major focus area as we consider this a best practice and seek to comply with regulations. While flaring is sometimes necessary, minimizing these volumes is a priority for us. To avoid flaring when possible, we restrict testing periods and connect our production to gas pipeline infrastructure as quickly as possible after well completions. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC, and can also be located at www.sec.gov. We also make available through our website our Corporate Governance Guidelines, Code of Business Conduct and Conflict of Interest Policy, Financial Code of Ethics, Human Rights Policy, and the Charters of the Audit, Compensation, Executive, and Environmental, Social and Governance committees of our Board of Directors. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in SM Energy.

Risks Related to Commodity Prices and Global Macroeconomics

Oil, gas, and NGL prices are volatile, and declines in prices may adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and gas properties depend heavily on the prices we receive for oil, gas, and NGL sales. Oil, gas, and NGL prices also affect our cash flows available for capital expenditures, debt reductions, return of capital, and other expenditures, our borrowing capacity, and the volume and value of our oil, gas, and NGL reserves. In addition, we may have oil and gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly. Please refer Refer to *Significant Developments in 2023 2024* and *Reserves* in Part I, Items 1 and 2, *Comparison of Financial Results and Trends Between 2024 and 2023 and Between 2023 and 2022* and *Overview of Liquidity and Between 2022 and 2021 Capital Resources* in Part II, Item 7, and *Note 1 – Summary of Significant Accounting Policies*, *Note 8 – Fair Value Measurements*, and *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 for specific discussion.

Historically, the markets for oil, gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil, gas, and NGL prices often result from relatively minor changes in the supply of and demand for oil, gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of oil, gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for oil, gas, and NGLs;
- overall global and domestic economic conditions;
- inflation and other economic factors that contribute to market volatility; volatility including tariffs and trade restrictions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, storage, and/or refining facilities in asset-specific or localized areas;
- liquefied natural gas deliveries to and from the United States;
- the increased demand for, price, and availability of alternative fuels or sources of energy;
- technological advances in, and regulations affecting, energy consumption and conservation;
- the ability of the members of OPEC+ to maintain effective oil price and production controls;
- political instability or armed conflict involving oil or gas producing countries or regions, such as instability in the Middle East, War and the wars between Russia and Ukraine and Israel and Hamas; Geopolitical Instability;
- shipping channel constraints and disruptions to and from oil and gas producing countries or regions;
- actual or perceived epidemic or pandemic risks;
- strengthening and weakening of the United States dollar relative to other currencies;
- stockholder activism or activities by non-governmental organizations to limit sources of funding or restrict the exploration and production of oil, gas, and NGLs and related infrastructure; and
- governmental regulations and taxes.

Declines in oil, gas, and NGL prices would reduce our revenues and could also reduce the amount of oil, gas, and NGLs that we can produce economically, which could have a material adverse effect on our business, financial condition, liquidity, results of operations, and prospects.

Future oil, gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and development costs are capitalized when incurred. Exploratory well costs are initially capitalized, pending the determination of whether proved reserves have been discovered. If commercial quantities of proved reserves are not discovered with an exploratory well, the costs initially capitalized are expensed as dry hole costs. During the years ended December 31, 2023, and 2022, we recorded amounts related to certain unsuccessful exploration activity to exploration expense.

The capitalized costs of our oil and gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net cash flows, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Write downs for unproved properties are also evaluated for carrying costs in excess of fair value. This evaluation considers the potential for abandonment due to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. Declines in the prices of oil, gas, or NGLs, or unsuccessful exploration efforts, could cause proved and/or unproved property impairments in the future, which could have a material adverse effect on our business, financial condition, liquidity, and results of operations.

We review the carrying values of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and gas properties held for use cannot be reversed at a later date, even if oil, gas, or NGL prices increase.

Weakness in economic conditions, continued inflation, or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

Historically, the United States and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility in prices of equity and debt securities, periods of diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, inflation, tariffs or trade restrictions, and heightened levels of intervention by the United States federal government and other governments. Weakness or uncertainty in the United States economy or other large economies could have a material adverse effect on our business and financial condition. For example:

- inflation has increased the certain costs of our drilling and completion activities, and the costs of oilfield services, equipment, and materials in recent years and could continue or worsen and further impact our financial condition, liquidity, and results of operations, and could limit our pool of economic development opportunities;
- a potential economic recession could impact demand for oil, gas, and NGLs, and cause commodity price volatility;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our Credit Agreement could be reduced if one or more any of our lenders is unable to fund its commitment;
- our ability, or the ability of our suppliers or contractors, to access the capital markets may be restricted or non-existent at a time when we or they would like, or need, to raise capital for our or their business, including for the exploration and/or development of reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection;
- the Federal Reserve could may change interest rates, as they did during in 2024, 2023, and 2022, and 2023, which could impact borrowing costs;
- variable interest rate spread levels, including for SOFR and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based rate-based borrowings under our Credit Agreement; and
- changes in tax laws and regulations could require us to adjust our business plan.

Global geopolitical tensions may create heightened volatility in oil, gas, and NGL prices and could adversely affect our business, financial condition and results of operations.

Global geopolitical tensions, including instability in the Middle East, War and the wars between Russia and Ukraine and Israel and Hamas, Geopolitical Instability could lead to significant market and other disruptions, including, but not limited to: significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, shipping channel constraints and disruptions, political and social instability, political and economic sanctions, geopolitical shifts, embargoes,

changes in consumer or purchaser preferences, the potential destruction of critical oil-related infrastructure, as well as increases in cyberattacks and espionage. These factors could impact our operations and the financial condition of our business as well as the global economy.

Risks Related to Oil and Gas Operations and the Industry

Integration of assets acquired in the recent Uinta Basin Acquisition with our existing business will be a complex and time-consuming process. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, financial condition, or results of operations.

The Uinta Basin Acquisition involved our acquisition of a significant set of assets that we have not previously operated. Our ability to achieve the anticipated benefits of the Uinta Basin Acquisition depends in part on whether we can complete the integration of the Uinta Basin assets into our existing business in an efficient and effective manner. The integration process may result in the disruption of ongoing business and there could be potential unknown liabilities and unforeseen expenses associated with the Uinta Basin Acquisition that were not discovered in the course of performing due diligence. The integration may also require significant time and focus from management following the Uinta Basin Acquisition that may disrupt our business and results of operations. Potential risks or difficulties include:

- operating assets in the Uinta Basin, an area in which we have not previously owned assets or conducted operations;
- operating assets that are partially within the exterior boundaries of the Uinta and Ouray Reservation, and we have no recent experience operating on tribal lands;
- complexities associated with integrating our existing complex systems, technologies, and other workflows with new assets in a new region;
- the inability to retain the services of key management and personnel;
- the accuracy of our assessments of the Uinta Basin Assets, including recoverable reserves, transportation costs and availability, drilling and completion equipment cost and availability, regulatory, permitting, and related matters;
- establishing business relationships with new third-party contractors and other service providers with whom we have no prior experience;
- operating in less familiar geological formations, with different legal and regulatory environments, different completion techniques, different transportation methods and operators, and unfamiliar operating conditions; and
- potential unknown liabilities and unforeseen increased expenses or delays associated with the Uinta Basin Acquisition.

Any of these issues could adversely affect our ability to maintain relationships with customers, suppliers, employees, and other constituencies. We may fail to realize the anticipated benefits expected from the Uinta Basin Acquisition. The success of the Uinta Basin Acquisition will depend, in significant part, on our ability to successfully complete the integration of the acquired assets, grow the revenue, and realize the anticipated strategic benefits from the Uinta Basin Acquisition. The anticipated benefits of the Uinta Basin Acquisition may not be realized fully or at all or may take longer to realize than expected. Actual operating, technological, strategic, and revenue opportunities, if achieved at all, may be less significant than expected or may take longer to achieve than anticipated. If we are not able to realize the anticipated benefits expected from the Uinta Basin Acquisition within the anticipated timing or at all, our business and operating results may be adversely affected.

We have incurred additional costs in connection with the Uinta Basin Acquisition, which may continue in 2025.

During 2024, we incurred non-recurring costs associated with the Uinta Basin Acquisition, integrating the Uinta Basin assets into our business, and realizing the expected benefits of the Uinta Basin Acquisition, and we expect to continue to incur such costs during a portion of 2025. A substantial majority of non-recurring expenses consist of transaction costs and include, among others, fees paid to financial, legal, accounting, and other advisors. Although we expect that the elimination of any duplicative costs, as well as the realization of expected benefits related to the integration of the Uinta Basin assets, should allow us to offset these transaction costs over time, this net benefit may not be achieved in the near term or at all.

Securities class action and derivative lawsuits may be brought against us in connection with the Uinta Basin Acquisition, which could result in substantial costs.

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.

The loss of personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team, other key personnel, and our general labor force. The loss of their services could adversely affect our business. Our success in drilling and completing new wells and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen, and other professionals. Competition for many of these professionals can be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

Our operations increasing dependence on digital technologies puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruptions or financial loss.

We are subject to complex laws and regulations, including environmental regulations, that result in substantial costs and other cybersecurity risks.

Federal, state, and local authorities extensively regulate the The oil and gas industry. Legislation industry, and regulations affecting the industry our business, are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing, or marketing of oil, gas, and NGL production. Non-compliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead increasingly dependent on digital technology. We use digital technology to increased operational and compliance costs, substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination conduct certain aspects of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, drilling development, production and abandon wells gathering activities, manage drilling rigs and related facilities completion equipment, gather and in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for interpret seismic data, conduct reservoir modeling, record financial and the production of operating data, and maintain employee and other databases. Our service providers, including those who gather, process, and market our oil, gas, and NGLs, including the permit are also increasingly reliant on digital technology. Our and bonding requirements of drilling wells, the spacing of wells, the unitization their reliance on this technology increasingly puts us at risk for technology system failures, data or pooling of interests network disruptions, cyberattacks and other breaches in oil and gas properties, rights-of-way and easements, disposal of produced water, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, restoration standards, and oil and gas operations. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit cybersecurity. Power failures, telecommunication or right-of-way grant other system failures due to hardware or impose conditions of approval to mitigate potential environmental impacts, which software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, flood, human error or other means could in either case, negatively affect significantly impair our ability to explore or develop certain properties. Any such delay, suspension, or termination could have a material adverse effect on conduct our operations. business.

Our operations Cybersecurity attacks are also subject evolving and include, but are not limited to, complex and constantly changing environmental laws and regulations adopted by federal, state, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes malicious software, attempts to current requirements, including the designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate in, could result in material costs or claims with respect gain unauthorized access to properties we own or have owned or limitations on exploration and production activities in certain locations. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and local environmental laws for emissions and for discharges of oil, gas, and NGLs data, cash, or other pollutants into assets, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Deliberate attacks on, or security breaches in our systems, infrastructure, the air, soil, surface water, systems and infrastructure of third-parties, or groundwater as described cloud-based applications could lead to disclosure of confidential information, a corruption or loss of our proprietary data, delays in *Government Regulations* production or exploration activities, difficulty in Part I, Items 1 completing or settling transactions, challenges in maintaining our books and 2 of this report. Existing records, environmental laws damage, communication or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered other operational disruptions, and liability to third parties. Any insurance we might obtain in the future may not provide adequate protection from these risks. Any such events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. As these cyber risks continue to evolve and our dependence on digital technologies grows, we may be required to expend significant additional resources to continue to modify or enhance our protective measures and remediate cyber vulnerabilities.

Refer to *Cybersecurity* in Item 1C of this report for discussion of the Audit Committee's role in cybersecurity governance. We did not experience any material cybersecurity incidents during 2024, however there can be no assurance that the measures we have a material adverse effect on us. taken to address information technology ("IT") and cybersecurity risks will prove effective in the future.

Federal We are incorporating artificial intelligence technologies into our processes and state legislative these technologies may present business, compliance, and reputational risks.

Our business increasingly utilizes artificial intelligence ("AI"), machine learning, and automated decision making to improve our processes. Issues in the development and use of AI, combined with an uncertain regulatory initiatives relating to hydraulic fracturing could environment, may result in increased costs and additional operating restrictions new or delays.

Hydraulic fracturing is a common practice in the oil and gas industry used enhanced governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability, or other adverse consequences to stimulate the production our business operations, all of oil, gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and gas properties, including our unconventional resource plays within our Midland Basin and South Texas assets. Hydraulic fracturing involves injecting water, sand, and certain chemicals under pressure to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities, as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act. The EPA also has authority under the Clean Water Act to regulate wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process and discharged to publicly-owned wastewater treatment facilities. If the EPA implements further regulations of hydraulic fracturing, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

Certain states, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict, or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event that state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

In the recent past, several federal governmental agencies were actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In 2013, a court in California, and in 2020, the United States District Court for the District of Montana, each held that the Bureau of Land Management ("BLM") did not comply with the National Environmental Policy Act ("NEPA") because it did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. In 2022, the federal Ninth Circuit Court of Appeals held that two federal agencies violated NEPA, in part, by failing to evaluate the environmental impacts of well stimulation treatments such as hydraulic fracturing before authorizing unconventional oil drilling offshore. Similar cases continue to be filed. In addition, courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for, and production of, oil, gas, and NGLs, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional state or local laws, or the implementation of new regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, business, results of operations, and cash flows. financial condition.

We will continue In addition, it is possible that AI and machine learning-technology could, unbeknownst to us, be subject improperly utilized by employees while carrying out their responsibilities. The use of AI can lead to uncertainty associated with new unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or generating content that appears correct but is factually inaccurate, misleading, biased, or otherwise flawed, which could harm our reputation and business and expose us to risks related to inaccuracies or errors in the output of such technologies. As the use of AI in our business becomes more prominent, we may be required to expend additional resources to further enhance our digital security, and we may face challenges in fully anticipating or implementing adequate preventive measures or mitigating potential harm. These costs may include deploying additional personnel and protection technologies, training employees, and engaging third party experts and consultants.

It is not possible to predict all of the risks related to the use of AI, machine learning and automated decision making, and developments in the regulatory suspensions, revisions or rescissions frameworks governing the use of such technologies and inconsistent state and federal regulatory mandates that could in related stakeholder expectations may adversely affect our production. ability to develop and use such technologies or subject us to liability. If we fail to successfully integrate AI into our business processes, or if we fail to keep pace with rapidly evolving AI technological developments, including attracting and retaining talented data scientists, data engineers, and programmers, we may face a competitive disadvantage.

Federal Competition in our industry is intense, and state regulatory initiatives relating many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from oil and gas exploration and production companies of all sizes for the capital, equipment, expertise, labor, and materials required to air quality operate oil and greenhouse gas emissions could properties. Many of our competitors have financial, technical, and other resources exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. As a result, we may not be successful in acquiring and developing profitable properties. In addition, other companies may have a greater ability to continue drilling activities during periods of low oil or gas prices and to absorb the burden of current and future governmental regulations and taxation. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs and additional operating restrictions or delays.

There has been a trend toward increased air quality and GHG regulation and reduced emissions from oil and gas sources. These regulations include the New Source Performance Standards ("NSPS"), the National Emission Standards for Hazardous Air Pollutants programs, and ozone standards set under the National Ambient Air Quality Standards ("NAAQS"), among others. The adoption of additional state or local laws, or the implementation inability to obtain those resources as needed. Our inability to compete effectively with companies in any area of new regulations could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows. Please refer to the *Environmental* section in Part II, Item 7 of this report for additional information about the regulation of air emissions, particularly methane emissions from the oil and gas sector.

Legislative and regulatory initiatives and litigation related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation and related expenses.

While courts have generally declined to assign direct liability for climate change to large sources of GHG emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant GHG emissions, and new claims for damages and increased government scrutiny, especially from state and local governments, will likely continue.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and the majority of states have already taken measures to reduce emissions of GHGs through various measures, including, primarily through the planned development of GHG emission inventories, participation in and/or regional GHG "cap and trade" programs, and/or transition to clean energy. The focus on legislating and/or regulating methane could result in increased scrutiny for sources emitting high levels of methane, including during permitting processes, analysis, regulation and reduction of methane emissions as a requirement for project approval, and actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors. In 2021, the EPA proposed requirements for methane emission reductions from existing oil and gas equipment. In 2022, the EPA released a supplemental proposal expanding its initial requirements as well as updating requirements, and in 2023, proposed updates to GHG reporting requirements. The 2022 and 2023 proposals are meant to work in tandem with the programs included in the Inflation Reduction Act of 2022 ("IRA").

The IRAimposes fees on emissions of GHGs, including methane, that exceed applicable thresholds. Our GHG emissions in 2023 did not exceed the thresholds set forth by the IRA, however, there is no assurance that we will be able to meet our goals or that we will not exceed the thresholds set forth by the IRA in the future. This and any court rulings, laws, or regulations that restrict or require reduced emissions of GHGs or introduce new climate-related regulations such as a carbon pricing system, could have an adverse effect on demand for the oil and gas that we produce, and could lead to increased operating and compliance costs, and litigation costs, which business could have a material adverse impact on our business. We have a long-term goal to reduce our Scope 1 and 2 GHG emissions intensity by 50 percent by 2030, compared with base year 2019 levels, and we have an annual goal to limit our methane emissions intensity to 0.04 (metric tonnes CH4/MBOE).

Scientists have predicted that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our drilling, completion, and production business activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such events. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements because emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes.

Requirements to reduce gas flaring could have an adverse effect on our operations.

In the Permian Basin in Texas, where we have significant operations, there have been, and could be in the future, constraints in gas takeaway capacity which has historically led to increased gas flaring. We are subject to laws established by state and other regulatory agencies that restrict the duration and amount of natural gas that can be legally flared. These laws and regulations, including potential future regulations that may impose further restrictions on flaring, could limit the amount of oil and gas we can produce from our wells or may limit the number of wells or the locations that we can drill. We have committed to zero routine flaring at all of our operated locations, and non-routine flaring not to exceed one percent of total annual gas production, based on the full year average. Additionally, we set annual targets to limit our flaring that are tied to compensation for all employees. There is no assurance that we will be able to meet our goals with respect to flaring and any failure to meet such goals could cause reputational or other harm to our business. Any future laws or commitments may increase our operational costs, or restrict our production, which could have a material adverse effect on our financial condition, and results of operations and cash flows.

The impact of extreme weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Our operations have been in the past, and may continue to be, adversely affected by the impact of extreme weather conditions. Additionally, lease stipulations designed to protect various wildlife or plant species may adversely impact our operations. In certain areas, drilling and other oil and gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs and completion equipment, oil field 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.

Our ability to produce oil, gas, and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and/or completions operations or are unable to dispose of or recycle the water we produce at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of oil, gas, and NGLs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of, or recycle, the water produced from our wells, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil, gas, and NGLs.

Compliance with environmental regulations, surface use agreements, and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Our ability to sell oil, gas, and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines, rail systems, and other transportation systems owned or operated by third-parties or by other interruptions beyond our control, which could obstruct, limit, or eliminate our access to oil, gas, and NGL markets.

The marketability of our oil, gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, pipelines, rail systems, and other transportation systems, which are generally owned or operated by third parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay, or discontinuance of development plans for our properties, increases in costs, or lower price realizations. Although we have some influence over the processing and transportation of our operated production, material changes in these business relationships could materially affect our operations. Federal, state, and state tribal regulation of oil, gas, and NGL production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines or processing facilities, infrastructure or capacity constraints, train derailments, and general economic conditions could adversely affect our ability to produce, gather, process, transport, or market oil, gas, and NGLs.

Production may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market or other conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flows and results of operations.

As part of the Uinta Basin Acquisition,our operations expanded to include the use of rail systems operated by third-parties to transport our crude oil to market which involves inherent risk, including the potential for accidents and derailments. In the event of a rail system accident or derailment, there could be significant delays in the delivery of oil to processing facilities, or impacts to rail system access or capacity, which may disrupt our business operations and could adversely affect our financial condition. Additionally, we could experience financial losses related to spills or damages to the oil in transit that we may not be able to recoup from the third-party rail operators. We continue to monitor our transportation arrangements and maintain contingency plans to mitigate potential impacts of transportation-related disruptions; however, we cannot guarantee that such measures will adequately reduce the risks associated with transportation by rail. During the fourth quarter of 2024, certain of our third-party rail operators experienced train and/or railcar derailments, one of which related to two railcars transporting our oil production in Jefferson, Texas. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for the definition of the Uinta Basin Acquisition.

We have entered into firm transportation contracts that require us to pay fixed sums of money to our counterparties regardless of the quantities actually shipped, processed, or gathered. transported under these contracts. If we are unable to deliver the necessary quantities of oil, gas, NGL, or produced water to our counterparties, our results of operations, financial position, and liquidity could be adversely affected.

As of December 31, 2023 December 31, 2024, we were contractually committed to deliver a minimum of 5 46 MMBbl of oil through July December of 2026 2028 and 11 3 MMBbl of produced water to certain disposal facilities through June of 2027. We may enter into additional firm transportation agreements as we expand the development of our resource plays. We do not expect to incur any material shortfalls related to our existing contractual commitments. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of operations, or delays in connecting new volumes to rail systems, gathering systems, or pipelines for an extended period of time, or if we further limit our capital expenditures due to future commodity price declines or for other reasons, the requirements to pay for quantities not delivered could have a material impact on our results of operations, financial position, and liquidity.

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

Some of our properties are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including the nature and timing of drilling and operational activities, the operator's skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the expenditures of such properties. These limitations and our dependence on the operator and other working interest owners in these projects could cause us to incur unexpected future costs.

We rely on third-party service providers to conduct drilling and completion and other related operations.

We rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, gas, and NGLs, prevailing economic conditions, and financial, business, and other factors. Future periods of sustained low commodity prices could occur and could cause third-party service providers to consolidate or declare bankruptcy, which could limit our options for engaging such providers. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil, gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other market conditions, including declines in oil, gas, and NGL prices. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell. We do not believe the loss of any single purchaser would materially impact our operating results, as we have numerous options for purchasers in each of our operating areas for our oil, gas, and NGL production. Refer to *Concentration of Credit Risk and Major Customers* in *Note 1 – Summary of Significant Accounting Policies,* in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers. Additionally, the inability of our co-owners, some of which have significant non-operated interests in a substantial portion of our oil and gas properties, to pay joint interest billings could negatively impact our cash flows and financial ability to drill and complete current and future wells.

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

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, result in increased lease operating expenses and adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Oil and gas drilling, completion, and production activities are subject to numerous risks, including the risk that no commercially producible oil, gas, or NGLs will be found.

The cost of drilling and completing wells is often uncertain, and oil, gas, or NGLs drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors may include, but are not limited to:

- supply chain issues, including cost increases and availability of equipment or materials;
- unexpected adverse drilling or completion conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes, tornadoes, flooding, wildfires, seasonal weather, or other adverse weather conditions;
- operational restrictions resulting from seismicity concerns;
- governmental permitting delays;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if oil, gas, or NGLs are present, or whether they can be produced economically. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of oil, gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, tribal, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore or develop our properties.

Results in newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. We, and the industry, generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of new plays; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

We may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases for such acreage will expire, and we will lose our right to develop the related properties. Our total net acreage as of January 31, 2025, that is scheduled to expire over the next three years, represents approximately 34 percent of our total net undeveloped acreage as of December 31, 2024. Although we have identified numerous potential drilling locations, we may not be able to economically drill for and produce oil, gas, or NGLs from all of them, and our actual drilling activities may materially differ from those presently identified, which could adversely affect our financial condition, results of operations and operating cash flow.

Our ability to produce oil, gas, and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and/or completions operations or are unable to dispose of or recycle the water we produce at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of oil, gas, and NGLs require the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of, or recycle, the water produced from our wells, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil, gas, and NGLs.

Compliance with environmental regulations, oil and gas leases, surface use agreements, and permit requirements governing the withdrawal, storage, and use of surface water and disposal or recycling of produced water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find or acquire and develop oil, gas, and NGL reserves that are economically producible. Our properties produce oil, gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate or acquire and develop new oil, gas, and NGL reserves to replace those being depleted by production.

For future acquisitions we may complete, a successful outcome for our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price and transaction costs for the acquisition, acquisition; future oil, gas, and NGL prices, prices; the ability to reasonably estimate the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, reserves; future operating and capital costs, costs; results of future exploration, exploitation, and development activities on the acquired properties, and properties; future abandonment and possible future environmental or other liabilities. liabilities; ability to attract and retain employees and contractors; success in transitioning ownership of the acquired properties; relationships with local regulatory authorities, landowners, and communities; and the ability to review and confirm the seller's title to the subject properties. There are numerous uncertainties inherent in estimating these variables with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. Our customary review in connection with acquisitions will not necessarily reveal, or allow us to fully assess, all existing or potential problems and deficiencies with such properties. We do not inspect every well, and even when we inspect a well, we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. liabilities, and we may not be able to obtain representation and warranty or similar insurance products on terms or at a price that efficiently manages the perceived or actual risk profile. We often acquire interests in properties on an "as-is" basis with limited remedies for breaches of representations and warranties.

Additionally, significant Significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties. For example, newly acquired properties if they may have substantially different operating and geological characteristics or are be in different geographic locations than our existing properties.

To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number If we are unable to replace any significant volume declines with additional volumes from other sources, our results of unique risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems cash flows could be materially and that unforeseen difficulties can arise in integrating operations and systems, and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions. adversely impacted.

The results of our operations are subject to drilling and completion technique risks, and results may not meet our expectations for reserves or production. As a result, we may incur material write-downs, and the value of our undeveloped acreage could decline if drilling and completion results are unsuccessful.

Many of our operations involve utilizing the latest drilling and completion techniques as developed by us, other operators and our service providers in order to maximize production and ultimate recoveries and therefore generate the highest possible returns. Risks we face while drilling include, but are not limited to, landing our well bore outside the desired drilling zone, deviating from the desired drilling zone while drilling horizontally through the formation, the inability to run our casing the entire length of the well bore, and the inability to run tools and recover equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, the inability to fracture stimulate the planned number of stages, the inability to run tools and other equipment the entire length of the well bore during completion operations, the inability to recover such tools and other equipment, and the inability to successfully clean out the well bore after completion of the final fracture stimulation.

In addition, exploration and drilling technologies we currently use or implement in the future may become obsolete. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected. We cannot be certain we will be able to implement exploration and drilling technologies on a timely basis or at a cost that is acceptable to us.

Ultimately, the success of exploration, drilling, and completion technologies and techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or prices for oil, gas, and NGLs decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from oil and gas exploration and production companies of all sizes for the capital, equipment, expertise, labor, and materials required to operate oil and gas properties. Many of our competitors have financial, technical, and other resources exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. As a result, we may not be successful in acquiring and developing profitable properties. In addition, other companies may have a greater ability to continue drilling activities during periods of low oil or gas prices and to absorb the burden of current and future governmental regulations and taxation. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. Our inability to compete effectively with companies in any area of our business could have a material adverse impact on our business activities, financial condition, and results of operations.

The actual quantities and present value of our proved oil, gas, and NGL reserves may be less than we have estimated, and the cost to develop our reserves may be more than we have estimated.

This report and certain of our other SEC filings contain estimates of our proved oil, gas, and NGL reserves and the present value of estimated future net revenues from those reserves. The process of estimating reserves is complex and estimates are based on various assumptions, including geological and geophysical characteristics, future oil, gas, and NGL prices, drilling, completion and other capital expenditures, gathering and transportation costs, operating expenses, effects of governmental regulation, taxes, timing of operations, and availability of funds. Therefore, these estimates are inherently imprecise. In addition, our reserve estimates for properties with limited production history may be less reliable than estimates for properties with lengthy production histories.

Actual future production; prices for oil, gas, and NGLs; revenues; production taxes; development expenditures; operating expenses; and quantities of producible oil, gas, and NGL reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities of, and present value related to proved reserves disclosed by us, and the actual quantities and present value may be significantly less than what we have previously estimated. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties, which we may not control.

As of December 31, 2023 December 31, 2024, 44 40 percent, or 263.6 274.3 MMBOE, of our estimated proved reserves were proved undeveloped. In order to develop our net proved undeveloped reserves, as of December 31, 2023 December 31, 2024, we estimate approximately $2.8 billion of capital expenditures would be required. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

One should not assume that the standardized measure of discounted future net cash flows or PV-10 included in this report represent the current market value of our estimated proved oil, gas, and NGL reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. Please refer Refer to *Reserves* in Part I, Items 1 and 2 of this report for discussion

regarding the prices used in estimating the present value of our proved reserves as of December 31, 2023 December 31, 2024, and to the caption *Oil and Gas Reserve Quantities* under *Critical Accounting Estimates* in Part II, Item 7 of this report for additional information.

The timing of production from oil and gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10. In addition, the 10 percent discount factor required by the SEC to calculate PV-10 for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and gas industry in general are subject.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly periodically sell non-core assets in order to increase capital resources available for core assets and other purposes and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in other core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties, the availability of purchaser financing and purchasers willing to acquire the assets on terms we deem acceptable, or other matters or uncertainties that could impact such dispositions, including whether transactions could be consummated or completed in the form or timing and for the value that we anticipate. At times, we may be required to retain certain liabilities or agree to indemnify buyers in connection with such asset sales. sales, or we may have to rely on third parties to perpetuate leases we intend to develop in the future. The magnitude of such retained liabilities or of the indemnification obligations may be difficult to quantify at the time of the transaction and ultimately could be material.

We rely on third-party service providers to conduct drilling and completion and other related operations.

We rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, gas, and NGLs, prevailing economic conditions, and financial, business, and other factors. Future periods of sustained low commodity prices could occur and could cause third-party service providers to consolidate or declare bankruptcy, which could limit our options for engaging such providers. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally rely on title due diligence reports when acquiring oil and gas leasehold interests, and we obtain title opinions prior to commencing initial drilling operations on the properties we operate. Title to the properties in which we have an interest may be impaired by title defects that may not be identified in the due diligence title reports or title opinions we obtain, or such defects may not be cured following identification. A material title defect can reduce the value of a property or render it worthless, thus adversely affecting our oil and gas reserves, financial condition, results of operations, and operating cash flow, and may also impair the value of or render adjacent properties uneconomic to develop. Undeveloped acreage has greater risk of title defects than developed acreage and title insurance is not generally available for oil and gas properties.

Oil Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and gas drilling, completion, and production activities are subject to numerous risks, including the risk that no commercially producible other disruptions.

As an oil, gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or NGLs to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts, including armed attacks on shipping channels. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be found.

The cost sufficient in preventing security threats from materializing. If any of drilling these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel, or capabilities essential to our operations and completing wells is often uncertain, and oil, gas, or NGLs drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors may include, but are not limited to:

- supply chain issues, including cost increases and availability of equipment or materials;
- unexpected adverse drilling or completion conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes, tornadoes, flooding, wildfires or other adverse weather conditions;
- operational restrictions resulting from seismicity concerns;
- governmental permitting delays;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if oil, gas, or NGLs are present, or whether they can be produced economically. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of oil, gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore reputation, financial position, results of operations, or develop our properties. cash flows.

Results in newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. We, The threat of terrorism and the industry, generally impact of military and other actions have less information with respect caused instability in world financial markets and could lead to the ultimate recoverability of reserves and the production decline rates increased volatility in newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of new plays; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

We may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases prices for such acreage will expire, and we will lose our right to develop the related properties. Our total net acreage as of February 8, 2024, that is scheduled to expire over the next three years, represents approximately 19 percent of our total net undeveloped acreage as of December 31, 2023. Although we have identified numerous potential drilling locations, we may not be able to economically drill for and produce oil, gas, or and NGLs, from all of them, and our actual drilling activities may materially differ from those presently identified, which could adversely affect the markets for our production. Energy assets might be specific targets of terrorist attacks. Depending on their occurrence and ultimate magnitude, terrorist threats or attacks could have a material adverse effect on our business, financial condition, or results of operations and operating cash flow.

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

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, result in increased lease operating expenses and adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil, gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other market conditions, including declines in oil, gas, and NGL prices. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell. We do not believe the loss of any single purchaser would materially impact our operating results, as we have numerous options for purchasers in each of our operating areas for our oil, gas, and NGL production. Please refer to *Concentration of Credit Risk and Major Customers* in *Note 1 – Summary of Significant Accounting Policies,* in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers. Additionally, the inability of our co-owners to pay joint interest billings could negatively impact our cash flows and financial ability to drill and complete current and future wells.

We are subject to operating and environmental risks and hazards that could result in substantial losses or liabilities that may not be fully insured.

Oil and gas operations are subject to many risks, including human error and accidents, that could cause personal injury, death, property damage, well blowouts, craterings, explosions, uncontrollable flows of oil, gas and NGLs, or well fluids, releases or spills of completion fluids, spills or releases from facilities and equipment used to deliver or store these materials, spills or releases of brine or other produced or flowback water, subsurface conditions that prevent us from stimulating the planned number of completion stages, accessing the entirety of the wellbore with our tools during completion, or removing materials from the wellbore to allow production to begin, fires, adverse weather such as hurricanes or tornadoes, freezing conditions, wildfires, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, train derailments, pollution, seismic events, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occur, we could sustain substantial losses.

In response to increased seismic activity in the Permian Basin in Texas, the Railroad Commission of Texas (“RRC”) has developed a seismic review process for injection wells near qualifying seismic activity. As a result of the seismic review process, the RRC may declare an area to be a Seismic Response Area (“SRA”) and may adjust limits for injection rates and pressure, require bottom-hole pressure tests, or modify, suspend, or terminate injection well permits within the SRA. If an SRA is declared within an area of our operations, our ability to dispose of produced water may be adversely affected, and as a result, we may be forced to shut-in injection wells or find alternate produced water disposal options which could affect production and therefore oil, gas, and NGL production revenue, and could cause us to incur additional capital or operating expense. The declaration of SRAs has required us to adjust the areas where we seek permits for injection wells to areas or formations that are less desirable, and could further restrict the areas where we are able to obtain and operate under such permits without restrictions. Additionally, we could be subject to third-party claims and liability based on allegations that our operations caused or contributed to seismic events that resulted in damage to property or personal injury, or that are otherwise related to seismic events.

If we experience any of the problems with well stimulation, completion activities, and disposal referenced above, our ability to explore for and produce oil, gas, and NGLs may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of the need to shut down, abandon, or relocate drilling operations, the need to modify drill sites to lessen the risk of spills or releases, the need to investigate and/or remediate any spills, releases or ground water contamination that might have occurred, and the need to suspend our operations.

There is an inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling, and disposal of materials, including produced water, solid and hazardous wastes, and petroleum hydrocarbons. We may incur joint and several, and/or strict liability under applicable United States federal and state environmental laws in connection with releases of hazardous substances at, on, under, or from our leased or owned properties, some of which have been used for oil and gas exploration and production activities for a number of years, often by third-parties not under our control. For our outside-operated properties, we are dependent on the operator for operational and regulatory compliance and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or therefrom could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including CERCLA or the Superfund law, RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under various implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury or property damage, including induced seismicity damage, allegedly caused by the release of petroleum hydrocarbons or other hazardous substances into the environment. As a result, we may incur substantial liabilities to third-parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by environmental damage that occurs gradually over time is appropriate for us at this time given the nature of our operations and the nature and cost of such coverage. Further, we may elect not to obtain insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer an uninsured material loss.

We The impact of seasonal and extreme weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Our operations have been in the past, and may continue to be, adversely affected by the impact of seasonal and extreme weather conditions. Additionally, lease stipulations designed to protect various wildlife or plant species may adversely impact our operations. In certain areas, drilling and other oil and gas activities can only be conducted during limited control times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs and completion equipment, oil field 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 Related to Government Regulations

Our operations are subject to complex laws and regulations, including environmental regulations, which result in substantial costs and other risks.

Federal, state, tribal, and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, and subject to constantly changing or differing interpretations, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing, or marketing of oil, gas, and NGL production. Non-compliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to increased operational and compliance costs, substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of oil, gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in oil and gas properties, rights-of-way and easements, disposal of produced water, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, restoration standards, and oil and gas operations. Public interest in environmental protection has increased over time, and environmental and other public interest organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Any such delay, suspension, or termination could have a material adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, including, among other things, air quality and GHG emissions standards and the activities on designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate in, could result in material costs or claims with respect to properties we do not operate. own or have owned or limitations on exploration and production activities in certain locations. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, tribal, and local environmental laws for emissions and for discharges of oil, gas, and NGLs or other pollutants into the air, soil, surface water, or groundwater as described in *Government Regulations* in Part I, Items 1 and 2 of this report. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a material adverse effect on us.

Some Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a common practice in the oil and gas industry used to stimulate the production of oil, gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and gas properties, including our unconventional resource plays within our Midland Basin, South Texas, and Uinta Basin assets. Hydraulic fracturing involves injecting water, sand, and certain chemicals under pressure to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities, as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act. The EPA also has authority under the Clean Water Act to regulate wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process and discharged to publicly-owned wastewater treatment facilities. If the EPA implements further regulations of hydraulic fracturing, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

Certain states, including Texas and Utah, have adopted or may adopt, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict, or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are operated playing out in several cities, counties, and townships across the United States. In the event that tribal, state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

In the recent past, several federal governmental agencies were actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In 2013, a court in California, and in 2020, the United States District Court for the District of Montana, each held that the BLM did not comply with the National Environmental Policy Act ("NEPA") because it did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. In 2022, the federal Ninth Circuit Court of Appeals held that two federal agencies violated NEPA, in part, by other companies failing to evaluate the environmental impacts of well stimulation treatments such as hydraulic fracturing before authorizing unconventional oil drilling offshore. Similar cases continue to be filed. In addition, courts in New York and involve third-party working interest Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. As a result, we have limited ability Litigation resulting in financial compensation for damages linked to influence hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or control regulation could also lead to operational delays or restrictions or increased costs in the operation or future exploration for, and production of, oil, gas, and NGLs, including from the development of such properties, including the nature and timing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of drilling and operational activities, the operator's skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, additional state or local laws, or the amount implementation of expenditures new regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

We will continue to be subject to uncertainty associated with new regulatory suspensions, revisions or rescissions and inconsistent state and federal regulatory mandates that could adversely affect our production.

Federal and state regulatory initiatives relating to air quality and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays.

There has been a trend toward increased air quality and GHG regulation and reduced emissions from oil and gas sources. These regulations include the New Source Performance Standards ("NSPS"), the National Emission Standards for Hazardous Air Pollutants programs, and ozone standards set under the National Ambient Air Quality Standards ("NAAQS"), among others. The adoption of additional state or local laws, or the implementation of new regulations could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows. Refer to the *Environmental* section in Part II, Item 7 of this report for additional information about the regulation of air emissions, particularly methane emissions from the oil and gas sector.

Additionally, certain areas where we currently operate (such as the Uinta Basin in Utah) or may operate in the future are or may be designated as ozone non-attainment areas, and are subject to stricter emissions regulations and control measures. These increased regulations and controls, which may increase over time, result in certain restrictions or limitations to our operations, increase our costs and may cause delays, which could affect our financial position, results of operations, and cash flows.

Legislative and regulatory initiatives and litigation related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation, capital, and related expenses.

While courts have generally declined to assign direct liability for climate change to large sources of GHG emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant GHG emissions, and new claims for damages and increased government scrutiny, especially from state and local governments, will likely continue.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and the majority of states have already taken measures to reduce emissions of GHGs through various measures, including, primarily through the planned development of GHG emission inventories, participation in and/or regional GHG "cap and trade" programs, and/or transition to clean energy. The focus on legislating and/or regulating methane could result in increased scrutiny for sources emitting high levels of methane, including during permitting processes, analysis, regulation and reduction of methane emissions as a requirement for project approval, and actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors. In 2021, the EPA proposed requirements for methane emission reductions from existing oil and gas equipment. In 2022, the EPA released a supplemental proposal expanding its initial requirements as well as updating requirements, and in 2023, proposed updates to GHG reporting requirements. In 2024, the EPA announced a final rule that facilitates the implementation of Congress's directive in the Inflation Reduction Act of 2022 ("IRA") to collect a waste emissions charge, and adds new reporting requirements for facilities and wells completed after May 7, 2024.

The IRAimposes fees on emissions of GHGs, including methane, that exceed applicable thresholds. Our GHG emissions in 2024 did not exceed the thresholds set forth by the IRA; however, there is no assurance that we will be required able to fund meet our goals or that we will not exceed the thresholds set forth by the IRA in the future. This and any court rulings, laws, or regulations that restrict or require reduced emissions of GHGs or introduce new climate-related regulations such as a carbon pricing system, could have an adverse effect on demand for the oil and gas that we produce, and could lead to increased operating and compliance costs, and litigation costs, which could have a material adverse impact on our business.

Scientists have predicted that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our drilling, completion, and production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies, or suppliers with respect whom we have a business relationship. We may not be able to such properties. Moreover, we are dependent on recover through insurance some or any of the other working interest owners damages, losses, or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements because emissions of such projects gases contribute to fund their contractual share warming of the expenditures of such properties. These limitations and our dependence on the operator earth's atmosphere and other working interest owners climatic changes.

Requirements to reduce gas flaring could have an adverse effect on our operations.

In the areas where we have significant operations, there have been, and could be, in these projects the future, constraints in gas takeaway capacity which has historically led to increased gas flaring. We are subject to laws established by state and other regulatory agencies that restrict the duration and amount of natural gas that can be legally flared. These laws and regulations, including potential future regulations that may impose further restrictions on flaring, could cause us to incur unexpected limit the amount of oil and gas we can produce from our wells or may limit the number of wells or the locations that we can drill. Any future costs. laws or commitments may increase our operational costs, or restrict our production, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Risks Related to Debt, Liquidity, and Access to Capital

Lower oil, gas, or NGL prices could limit our ability to borrow under our Credit Agreement.

As of December 31, 2023 December 31, 2024, the borrowing base and aggregate revolving lender commitments under our Credit Agreement were $2.5 $3.0 billion and $1.25 $2.0 billion, respectively. The borrowing base is subject to semi-annual redetermination based on the bank group's assessment of the value of our proved reserves, which in turn is impacted by oil, gas, and NGL prices. The next borrowing base redetermination date is scheduled for April 1, 2024 to occur on April 1, 2025. Divestitures of properties, incurrence of additional debt, or declines in commodity prices could limit our borrowing base and reduce the amount we can borrow under our Credit Agreement, which could in turn impact, among other things, our ability to service our debt, fund our capital program, or compete for the acquisition of new properties.

Negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole could adversely affect our business, operations, and our ability to attract capital.

Certain segments of the public as a whole, and the investment community in particular, have developed negative sentiment toward our industry. In recent years, equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment management firms, sovereign wealth and pension funds, university endowments and other investment advisors, have adopted policies to discontinue or reduce their investments in the oil and gas sector based on social and environmental considerations. Furthermore, other influential stakeholders have pressured commercial and investment banks and other service providers to reduce or cease financing of oil and gas companies and related infrastructure projects.

Such developments, including increased focus on environmental, social and governance matters and initiatives aimed at limiting climate change and reducing air pollution, and changes in federal income tax laws could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Substantial capital is required to develop and replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce oil, gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for oil, gas, and NGL sales, our success in locating, developing, acquiring, and acquiring developing new reserves, and the orderly functioning of credit and capital markets. If our cash flows from operations are less than expected, we may reduce our planned capital expenditures. If we cannot access sufficient liquidity under our Credit Agreement, or raise additional funds through debt or equity financing or the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Downgrades in our credit ratings by various credit rating agencies could impact our access to capital and have a material adverse effect on our business and financial condition.

Downgrades of our credit ratings could have material adverse consequences on our business and future prospects and could:

- limit our ability to access capital markets, including for the purpose of refinancing our existing debt;
- cause us to refinance or issue debt with less favorable terms and conditions, which may restrict, among other things, our ability to make any dividend payments or repurchase shares;
- negatively impact lenders' willingness to transact business with us, which could impact our ability to obtain favorable terms and conditions under our Credit Agreement;
- negatively impact current and prospective customers' willingness to transact business with us;
- impose additional insurance, guarantee, bonding, and collateral requirements;
- limit our access to bank and third-party guarantees, surety bonds, and letters of credit; and
- cause our suppliers and financial institutions to lower or eliminate the level of credit provided through payment terms or intraday funding when dealing with us, thereby increasing the need for higher levels of cash on hand, which would decrease our ability to repay outstanding indebtedness.

We cannot provide assurance that any of our current credit ratings will remain in effect for any given period of time or that a credit rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant.

Our commodity derivative contract activities may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales.

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, we regularly enter into commodity derivative contracts. Our commodity derivative contracts typically include price swap swaps and collar arrangements for oil, gas, and NGLs. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

In addition, commodity derivative contracts may limit the prices we receive for our oil, gas, and NGL sales if oil, gas, or NGL prices rise substantially over the price established by the commodity derivative contract. Please refer Refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional detail regarding our commodity derivative contracts.

The amount of our debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2023 December 31, 2024, we had $1.6 $2.7 billion of aggregate principal amount outstanding of Senior Notes with maturities through 2028, 2032, as further discussed and defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. We had no $68.5 million outstanding balance on our revolving credit facility and had $1.2 $1.9 billion of available borrowing capacity under our Credit Agreement as of December 31, 2023 December 31, 2024. Our long-term debt represented 30 40 percent of our total book capitalization as of December 31, 2023 December 31, 2024.

The amounts of our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;
- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to capital investments;
- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends; dividends or repurchasing shares of common stock;
- placing us at a competitive disadvantage compared to our competitors with less debt; and
- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our Credit Agreement or from other sources, we might not be able to service our debt, issue additional debt, or fund our planned capital expenditures and other liquidity needs. If we are unable to service our debt due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, and/or restructure or refinance our debt. We might not be able to sell our equity, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our Credit Agreement and any future credit agreements, may prohibit us from pursuing any of these alternatives.

As discussed above, our Credit Agreement is subject to periodic borrowing base redeterminations. At times when we have an outstanding balance, we could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate adjustments to our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt arrangements contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements, including our Credit Agreement and the indentures governing our Senior Notes, contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests, including restrictions on incurring debt, issuing dividends, repurchasing common stock, selling assets, creating liens, entering into transactions with affiliates, and merging, consolidating, or selling our assets. Our ability to borrow under our Credit Agreement is subject to compliance with certain financial and non-financial covenants, as outlined in the Credit Agreement. Please refer Refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion. These restrictions on our ability to operate our business could significantly harm us by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

Negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole could adversely affect our business, operations, and our ability to attract capital.

Certain segments of the public as a whole, and the investment community in particular, have developed negative sentiment toward our industry. In recent years, equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment management firms, sovereign wealth and pension funds, university endowments and other investment advisors, have adopted policies to discontinue or reduce their investments in the oil and gas sector based on social and environmental considerations. Furthermore, other influential stakeholders have pressured commercial and investment banks and other service providers to reduce or cease financing of oil and gas companies and related infrastructure projects.

Such developments, including increased focus on environmental, social and governance matters and initiatives aimed at limiting climate change and reducing air pollution, and changes in federal income tax laws could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Risks Related to Corporate Governance and Ownership of Public Equity Securities

Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment, which could adversely affect the price of our common stock.

Delaware corporate law and our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control of us or our management. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price investors are willing to pay in the future for shares of our common stock.

In addition, stockholder activism in our industry has been present in recent years, and if investors seek to exert influence or affect changes to our business that we do not believe are in the long-term best interests of our stockholders, such actions could adversely impact our business by, among other things, distracting our Board of Directors and management team, causing us to incur unexpected advisory fees and other related costs, impacting execution of our strategic objectives, and creating unnecessary market uncertainty.

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2023 January 1, 2024, to February 8, 2024 January 31, 2025, the intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of $24.66 $34.76 per share in March 2023 January 2024 to a high of $43.73 $53.26 per share in October 2023. April 2024. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include, in addition to the other risk factors set forth herein, the following:

- changes in oil, gas, or NGL prices;
- changes in the outlook for regional, national, or global commodity supply and demand;
- variations in drilling, recompletion, and operating activity;
- inflation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- increased volatility due to the impacts of algorithmic trading practices;
- future sales of our common stock;
- negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole;
- changes in the national and global economic outlook, including potential impacts from trade agreements; agreements or tariffs; and

- international trade relationships, potentially including the effects of trade restrictions or tariffs affecting the raw materials we utilize and the commodities we produce in our business.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

We may not always pay dividends on our common stock or repurchase common stock under our Stock Repurchase Program.

Payment of future dividends remains at the discretion of our Board of Directors, and common stock repurchases under our Stock Repurchase Program remain at the discretion of our Board of Directors and certain authorized officers of the Company. Decisions regarding the payment of dividends and the repurchase of common stock will continue to depend on our earnings, capital requirements, financial condition, general market and economic conditions, applicable legal requirements, the market price of our common stock, and other factors. The payment of dividends and the repurchase of our common stock are each subject to covenants in our Credit Agreement and in the indentures governing our Senior Notes that could limit our ability to make certain restricted payments including dividends and common stock repurchases. Our Board of Directors may determine in the future to reduce the current annual dividend rate or discontinue the payment of dividends altogether. The value of shares authorized for repurchase by the Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of our shares will be repurchased.

General Risk Factors

Our increasing dependence on digital technologies puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruptions or financial loss.

We are subject to cybersecurity risks. The oil and gas industry, and our business, are increasingly dependent on digital technology. We use digital technology to conduct certain aspects of our drilling development, production and gathering activities, manage drilling rigs and completion equipment, gather and interpret seismic data, conduct reservoir modeling, record financial and operating data, and maintain employee and other databases. Our service providers, including those who gather, process, and market our oil, gas, and NGLs, are also increasingly reliant on digital technology. Our and their reliance on this technology increasingly puts us at risk for technology system failures, data or network disruptions, cyberattacks and other breaches in cybersecurity. Power failures, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, flood, human error or other means could significantly impair our ability to conduct our business.

Cybersecurity attacks are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, cash, or other assets, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Deliberate attacks on, or security breaches in our systems, infrastructure, the systems and infrastructure of third-parties, or cloud-based applications could lead to disclosure of confidential information, a corruption or loss of our proprietary data, delays in production or exploration activities, difficulty in completing or settling transactions, challenges in maintaining our books and records, environmental damage, communication or other operational disruptions, and liability to third parties. Any insurance we might obtain in the future may not provide adequate protection from these risks. Any such events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. As these cyber risks continue to evolve and our dependence on digital technologies grows, we may be required to expend significant additional resources to continue to modify or enhance our protective measures and remediate cyber vulnerabilities.

Please refer to *Cybersecurity Risk Management, Strategy, and Governance* in Item 1C of this report for discussion of the Audit Committee's role in cybersecurity governance. We did not experience any material cybersecurity incidents during 2023, however there can be no assurance that the measures we have taken to address information technology ("IT") and cybersecurity risks will prove effective in the future.

We are incorporating artificial intelligence technologies into our processes and these technologies may present business, compliance, and reputational risks.

Our business increasingly utilizes artificial intelligence ("AI"), machine learning, and automated decision making to improve our processes. Issues in the development and use of AI, combined with an uncertain regulatory environment, may result in new or enhanced governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability, or other adverse consequences to our business operations, all of which could adversely affect our business, results of operations, and financial condition.

In addition, it is possible that AI and machine learning-technology could, unbeknownst to us, be improperly utilized by employees while carrying out their responsibilities. The use of AI can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or generating content that appears correct but is factually inaccurate, misleading, or otherwise flawed, which could harm our reputation and business and expose us to risks related to inaccuracies or errors in the output of such technologies. It is not possible to predict all of the risks related to the use of AI, machine learning and automated decision making, and developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations may adversely affect our ability to develop and use such technologies or subject us to liability. If we fail to successfully integrate AI into our business processes, or if we fail to keep pace with rapidly evolving AI technological developments, including attracting and retaining talented data scientists, data engineers, and programmers, we may face a competitive disadvantage.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.

As an oil, gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts, including armed attacks on shipping channels. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel, or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

The threat of terrorism and the impact of military and other actions have caused instability in world financial markets and could lead to increased volatility in prices for oil, gas, and NGLs, all of which could adversely affect the markets for our production. Energy assets might be specific targets of terrorist attacks. Depending on their occurrence and ultimate magnitude, terrorist threats or attacks could have a material adverse effect on our business, financial condition, or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 1C. CYBERSECURITY RISK MANAGEMENT, STRATEGY, AND GOVERNANCE

Risk Management and Strategy

We believe that mitigating cybersecurity risks is the responsibility of every employee. We take a preventative approach with respect to cybersecurity threats by building a resilient cybersecurity culture and strong IT infrastructure. Our processes for assessing, identifying, and managing material risks from cybersecurity threats include:

- monitoring the threat landscape and taking measures to enhance our cybersecurity program to adapt to new and developing risks;
- ongoing training, testing, and utilizing other forms of social engineering awareness and education for our employees;
- using cybersecurity systems and tools to monitor endpoints and environment logs in a centralized security information and event management system with capabilities for reporting and alerting on known threats and anomalous behaviors;
- assessing the cybersecurity practices and external ratings and assessments of certain of our third-party technology and data vendors and service providers, and maintaining preventative controls and monitoring systems related to these partners;
- creating and testing various incident response plans to hypothetical cybersecurity attacks in order to quickly assess and respond to potential and actual threats;
- utilizing engaging third-party cybersecurity experts and consultants to perform penetration testing and scanning of our systems for vulnerabilities;
- obtaining third-party security maturity assessments, benchmarking, and security effectiveness ratings of our cybersecurity program; and
- maintaining a retainer for incident response services with a trusted cybersecurity partner in order to quickly respond, investigate, contain, and recover in the event of a cybersecurity incident.

We have structured our cybersecurity risk management program according to the National Institute of Standards and Technology Cybersecurity Framework. We strive to employ cybersecurity best practices, including implementing new technologies to proactively monitor new threats and vulnerabilities and reduce risk; maintaining a Cybersecurity Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan; and regularly updating our response planning and protocols. We have integrated our cybersecurity processes into our overall risk management program, thereby establishing a comprehensive approach by which we determine and implement strategies designed to manage external, strategic, operational and financial risks to our business, including cybersecurity threats.

We utilize a wide range of protective cybersecurity technologies and tools, including, but not limited to, encryption, firewalls, endpoint detection and response, security information and event management, multi-factor authentication, and threat intelligence feeds. In addition, we use an information security risk management approach that includes monitoring security threats and trends in the industry, analyzing potential security risks that could impact the business, partnering with industry recognized security organizations, and coordinating an appropriate response should the need arise.

Cybersecurity threats and incidents could have a material impact on our financial condition and results of operations. A successful cyber-attack could lead to operational disruptions, financial losses, regulatory penalties, reputational damage, and legal liabilities. In some cases, the costs associated with investigating and remediating a cybersecurity incident, as well as potential litigation and regulatory fines, could result in a material impact to our financial condition and results of operations. During 2023, 2024, we did not experience any cybersecurity incidents that materially affected or are reasonably likely to materially affect us, including our business strategy, results of operations, or financial condition, however, there can be no assurance that the measures we have taken to address IT and cybersecurity risks will prove effective in the future. For additional discussion of the IT and cybersecurity risks facing our business, please refer to *Risk Factors* in Part 1, Item 1A of this report.

We prioritize investment in cybersecurity risk management and governance. We continually assess the adequacy of our resources and capabilities to address emerging threats, regulatory requirements, and changes in technology. As cybersecurity threats evolve, we may need to further enhance our processes and technologies, which could require additional financial resources.

Governance

Our Board of Directors receives regular updates on relevant IT matters affecting the Company, including cybersecurity risks and mitigation strategies. In addition to the general oversight provided by the full Board of Directors, the Audit Committee is responsible for oversight of our risk assessment and management processes, including with respect to IT and cybersecurity risks. The Audit Committee receives a quarterly cybersecurity report and regular updates from our Vice President and Chief Information Officer and our Director of Cybersecurity Risk and Business Continuity, which includes, among other information, the steps management has taken, and the specific guidelines and policies that have been established, to monitor, control, mitigate and report exposure to IT and cybersecurity risk.

We have established a Cyber Incident Response Team (“CIRT”) to provide an efficient, effective, and orderly response to technology related incidents and our Cybersecurity Incident Response Plan contains protocols for communication within this team and reporting to executive management and the Audit Committee.

The CIRT is led by our Vice President and Chief Information Officer and Director of Cybersecurity Risk and Business Continuity. Together, these professionals are responsible for assessing and managing cybersecurity risks and they lead a team of specialized technologists entrusted with ensuring the functionality, continuity, and security of our technology infrastructure and data. Our Vice President and Chief Information Officer is a seasoned IT professional with over 28 29 years of experience encompassing all facets of IT within the energy industry. His extensive background comprises managing IT service delivery, designing and administering secure solutions, establishing robust IT and Internet of Things infrastructures, and effectively managing technology-related risks. His skill set includes proficiency in threat mitigation, comprehensive risk assessment, and integration of cybersecurity strategies into business operations designed to safeguard critical assets and sensitive data. He reports to our Executive Vice President and Chief Financial Officer. Our Director of Cybersecurity Risk and Business Continuity has over 23 24 years of experience in the IT field with a majority of that time focused on designing, building and maintaining technology systems. His experience includes implementing security solutions and processes with a focus on adapting to the evolving cybersecurity threat landscape. He is a skilled leader and reports to our Executive Vice President and Chief Financial Officer.

ITEM 3. LEGAL PROCEEDINGS

At times, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing of this report, no legal proceedings are pending against us that we believe individually or collectively are likely to have a material adverse effect upon our financial condition, results of operations, or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable The required disclosure under Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to us. this report.

PART II

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

Our common stock is currently traded on the New York Stock Exchange under the ticker symbol "SM." For dividend information, please refer to the caption *Uses of Cash* in *Overview of Liquidity and Capital Resources* in Item 7 of this report. Information regarding the SM Energy Equity Incentive Compensation Plan, as amended and restated effective as of May 22, 2018 (the "Equity Plan"), and the securities authorized under the Equity Plan is included below.

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2018 December 31, 2019, and ending December 31, 2023 December 31, 2024, with the cumulative total returns of the Dow Jones Exploration and Production Index ("DJUSOS"), and the Standard & Poor's 500 Stock Index ("SPX").

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS

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The preceding information under the caption *Performance Graph* shall be deemed to be furnished, but not filed with the SEC.

Holders. As of February 8, 2024 January 31, 2025, the number of record holders of our common stock was 102. 111. A substantially greater number of holders of our common stock are beneficial holders, whose shares of record are held by banks, brokers, and other financial institutions.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. The following table provides information about purchases made by us and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and months, and the year ended December 31, 2023 December 31, 2024, of shares of our common stock, which is the sole class of equity securities registered by us pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS				
Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program (2)	Maximum Number or Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (as of the period end date) (2)
First quarter of 2023	1,413,758	$ 28.32	1,413,758	$ 402,780,476
Second quarter of 2023	2,550,976	$ 26.95	2,550,706	$ 334,036,922
Third quarter of 2023	2,600,605	$ 40.07	2,351,642	$ 237,700,848
10/01/2023 - 10/31/2023	—	$ —	—	$ 237,700,848
11/01/2023 - 11/30/2023	614,729	$ 37.16	614,729	$ 214,854,687
12/01/2023 - 12/31/2023	—	$ —	—	$ 214,854,687
Total	7,180,068	$ 32.85	6,930,835	

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS				
Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program (2)	Maximum Number or Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (as of the period end date) (2)
First quarter of 2024	712,844	$ 45.98	712,235	$ 182,101,195
Second quarter of 2024	1,058,956	$ 48.35	1,058,956	$ 500,000,000
Third quarter of 2024	157,643	$ 43.23	—	$ 500,000,000
10/01/2024 - 10/31/2024	—	$ —	—	$ 500,000,000
11/01/2024 - 11/30/2024	—	$ —	—	$ 500,000,000
12/01/2024 - 12/31/2024	—	$ —	—	$ 500,000,000
Total	1,929,443	$ 47.06	1,771,191	

(1) 249,233 158,252 shares purchased by us in 2023 2024 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying Restricted Stock Units ("RSU" or "RSUs") issued under the terms of award agreements granted under the Equity Plan.

(2) Our In June 2024, our Board of Directors re-authorized the existing Stock Repurchase Program, which authorizes and authorized us to repurchase up to $500.0 million in aggregate value of our common stock through December 31, 2024, December 31, 2027. The Stock Repurchase Program permits us to repurchase our shares from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws and subject to certain provisions of our Credit Agreement and the indentures governing our Senior Notes. The timing, as well as the number and value of shares repurchased under the Stock Repurchase Program, is determined by certain authorized officers of the Company at their discretion and depends on a variety of factors, including the market price of our common stock, general market and economic conditions and applicable legal requirements. The value of shares authorized for repurchase by our Board of Directors does not require us to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of our shares will be repurchased. During the year ended December

31, 2023 December 31, 2024, we repurchased and subsequently retired 6,930,835 1,771,191 shares of our common stock under the Stock Repurchase Program at a weighted-average share price of $32.89 $47.40 for a total cost of $228.0 $84.0 million, excluding excise taxes, commissions and fees.

Our payment of cash dividends to our stockholders and repurchases of our common stock are each subject to certain covenants under the terms of our Credit Agreement and Senior Notes. Based on our current performance, we do not anticipate that any of these covenants will limit our potential repurchases of our common stock or our payment of dividends at our current rate for the foreseeable future if any dividends are declared by our Board of Directors.

During the year ended December 31, 2023 December 31, 2024, we paid $71.6 $85.0 million in dividends to our stockholders. Dividends paid reflects $0.60 reflect $0.74 per share during the year ended December 31, 2023 December 31, 2024. During 2023, our Board of Directors approved a 20 percent increase to our fixed dividend to $0.72 per share annually, to be paid in quarterly increments of $0.18 per share, beginning in the first quarter of 2024. We currently intend to continue paying dividends to our stockholders for the foreseeable future, subject to our future earnings, our financial condition, covenants under our Credit Agreement and indentures governing each series of our outstanding Senior Notes, and other factors that could arise. The payment and amount of future dividends remain at the discretion of our Board of Directors.

ITEM 6. [RESERVED]

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

The following discussion includes forward-looking statements. Please refer Refer to the *Cautionary Information about Forward-Looking Statements* section of this report for important information about these types of statements.

Overview of the Company

General Overview

Our purpose is to make people's lives better by responsibly producing energy supplies, contributing to domestic energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision and strategy is to sustainably grow value for all of our stakeholders as a premier operator of top-tier assets by maintaining and optimizing our high-quality asset portfolio, generating cash flows, and maintaining a strong balance sheet. Our team executes this strategy by prioritizing safety, technological innovation, and stewardship of natural resources, all of which are integral to our corporate culture. Our near-term goals include continuing focusing on operational execution and successfully integrating the Uinta Basin assets; generating cash flows that enable us to return continue returning value to stockholders through fixed dividend payments, debt repayments, and our Stock Repurchase Program Program; and fixed dividend payments, expanding our portfolio of top-tier economic drilling inventory through acquisition and by focusing on continued operational excellence. exploration.

Our asset portfolio is comprised of high-quality assets in the Midland Basin of West Texas, and in the Maverick Basin of South Texas, that and the Uinta Basin of northeastern Utah, which we believe are capable of generating strong returns in the current macroeconomic environment and provide resilience to commodity price risk and volatility. We seek to maximize returns and increase the value of our top-tier assets through disciplined capital spending, strategic acquisitions, including the Uinta Basin Acquisition, and continued development and optimization of our existing assets. We believe that our high-quality assets facilitate a sustainable approach to prioritizing operational execution, maintaining a strong balance sheet, generating cash flows, returning capital to stockholders, and maintaining financial flexibility. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and for the definition of the Uinta Basin Acquisition.

We are committed to exceptional safety, health, and environmental stewardship; supporting the professional development of a diverse and thriving team of employees; building and maintaining partnerships with our stakeholders by investing in and connecting with the communities where we live and work; and transparency in reporting our progress in these areas. The Environmental, Social and Governance Committee of our Board of Directors oversees, among other things, the effectiveness of our ESG policies, programs and initiatives, monitors and responds to emerging trends, issues, and associated risks, and, together with management, reports to our Board of Directors regarding such matters. Further demonstrating our commitment to sustainable operations and environmental stewardship, compensation for our executives and eligible employees under our long-term incentive plan, and compensation for all employees under our short-term incentive plan is calculated based on, in part, certain Company-wide, performance-based metrics that include key financial, operational, environmental, health, and safety measures. Please refer Refer to our Definitive Proxy Statement on Schedule 14A for the 2024 2025 annual meeting of stockholders to be filed within 120 days from December 31, 2023 December 31, 2024, for additional discussion. discussion of our compensation programs.

We are impacted affected by global commodity and financial markets that remain subject to heightened levels of uncertainty and volatility. While the rate of inflation in the United States has decreased since the beginning of the year and the average rate of inflation in 2023 was lower than it was in 2022, inflation continues Key factors contributing to impact certain aspects of our business. Continued market fluctuations include ongoing oil production curtailment agreements among OPEC+, instability fluctuations in the Middle East, economic oil and trade sanctions associated with the wars between Russia gas demand from China, War and Ukraine and Israel and Hamas, Geopolitical Instability, United States Federal Reserve monetary policy, shipping channel constraints and disruptions, tariffs or trade restrictions, and changes in global oil inventory in storage storage. These factors have driven commodity price volatility, contributed to instances of supply chain disruptions and fluctuations in interest rates, and could have further industry-specific impacts that may require us to adjust our business plan. Future impacts of these and other events on commodity and financial markets are inherently unpredictable. Despite continuing uncertainty, we expect to maximize the value of our high-quality asset base and sustain strong operational performance and financial stability. We remain focused on returning generating cash flows to enable us to return capital to stockholders through cash flow generation. and reduce our debt.

Outlook

We expect our total 2024 2025 capital program to be between $1.16 billion and $1.20 billion approximately $1.3 billion, excluding acquisitions, which we expect to fund with cash flows from operations, and with any remaining cash on hand. needs being funded by borrowings under our revolving credit facility. We plan to focus our 2024 2025 capital program on highly economic oil development projects in both our Midland Basin, and South Texas, assets, including the assets we acquired during 2023. We expect and Uinta Basin assets. Refer to repurchase additional shares of our outstanding common stock through our Stock Repurchase Program during 2024, under which $214.9 million remains available for repurchases through December 31, 2024, as of the filing *Outlook* in Part I, Items 1 and 2 of this report. report for additional discussion.

2023 2024 Financial and Operational Highlights

During 2023, we increased 2024:

- We expanded our operations into Utah upon the completion of the Uinta Basin Acquisition during the fourth quarter of 2024. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

- We issued a combined $1.5 billion of aggregate principal amount of capital we returned our 2029 Senior Notes and 2032 Senior Notes and redeemed the remaining $349.1 million aggregate principal amount outstanding of our 2025 Senior Notes. Refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.
- Our Board of Directors approved an increase to our stockholders, compared with 2022, through repurchases fixed dividend to $0.80 per share annually, to be paid in quarterly increments of our outstanding common stock under our Stock Repurchase Program and our fixed quarterly $0.20 per share, which commenced in the fourth quarter of 2024. We paid a net cash dividend payments, and we expanded our Midland Basin asset position. of $0.74 per share, an increase from $0.60 per share paid during 2023. Refer to *Note 3 – Equity* in Part II, Item 8 of this report for additional discussion.
- During the year ended December 31, 2023, first half of 2024, we repurchased and subsequently retired 6.9 1.8 million shares of our common stock at a cost of $228.0 $84.0 million, excluding excise taxes, commissions, and fees; we paid dividends fees. In June 2024, our Board of $0.60 per share, an increase from $0.16 per share paid during Directors re-authorized our existing Stock Repurchase Program, and as of December 31, 2024, $500.0 million remained available under the year ended December 31, 2022; and we announced a 20 percent increase to Stock Repurchase Program for repurchases of our fixed dividend to $0.72 per share annually, to be paid in quarterly increments of $0.18 per share, beginning in the first quarter of 2024. Additionally, we executed strategic acquisitions, exchanges, and leasing activity in the Midland Basin, enabling us to enhance

our capital efficiency by blocking up acreage and maintaining high working interests. Please refer common stock through December 31, 2027. Refer to *Note 3 – Equity* and *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion.

Financial and Operational Results. Average net daily equivalent production for the year ended December 31, 2023 December 31, 2024, increased five 12 percent to 152.0 170.5 MBOE, compared with 145.1 152.0 MBOE for 2022 2023, as a result of strong well performance, an increased number of completions, in 2023 compared with 2022. and production from our Uinta Basin assets during the fourth quarter of 2024. The total increase primarily consisted of a 20 percent increase from our South Texas assets, partially offset by a increases of seven percent decrease and six percent from our Midland Basin and South Texas assets, respectively, and 9.1 MBOE of production from our Uinta Basin assets. These changes were

Realized prices for oil and gas decreased two percent and 27 percent, respectively, for the year ended December 31, 2024, compared with 2023, as a result of decreases in oil and gas benchmark commodity prices. Realized price for NGLs remained flat for the year ended December 31, 2024, compared with 2023. Total realized price per BOE remained flat for the year ended December 31, 2024, compared with 2023, primarily driven by a 24 percent increase in oil production, offset by decreases in oil and gas benchmark commodity prices. Oil, gas, and NGL production revenue increased 13 percent to $2.7 billion for the year ended December 31, 2024, compared with $2.4 billion for 2023, primarily as a result of the timing of well completions, strong well performance, and production from our Uinta Basin assets during the timing fourth quarter of capital expenditures during 2022 and 2023.

Realized prices for oil, gas, and NGLs decreased 19 percent, 61 percent, and 35 percent, respectively, for the year ended December 31, 2023, compared with 2022, as a result of decreases in benchmark commodity prices during 2023. Total realized price per BOE decreased 33 percent for the year ended December 31, 2023, compared with 2022, resulting in a 29 percent decrease in oil, gas, and NGL production revenue, which was $2.4 billion for the year ended December 31, 2023, compared with $3.3 billion for 2022. 2024. Oil, gas, and NGL production expense of $10.16 $10.21 per BOE for the year ended December 31, 2023 December 31, 2024, decreased 13 percent remained flat, compared with 2022, primarily as a result of decreases in production tax expense per BOE, transportation costs per BOE, and ad valorem tax expense per BOE, partially offset by an increase in LOE per BOE. 2023.

We recorded a net derivative gain gains of $50.0 million and $68.2 million for the year years ended December 31, 2023 December 31, 2024, compared to a net derivative loss of $374.0 million for 2022. and 2023, respectively. These amounts include a net derivative settlement gain gains of $68.7 million and $26.9 million for the year years ended December 31, 2023 December 31, 2024, and a net derivative settlement loss of $710.7 million for the year ended December 31, 2022. 2023, respectively.

Operational activities during the year ended December 31, 2023 December 31, 2024, resulted in the following:

- Net cash provided by operating activities of $1.6 $1.8 billion, compared with $1.7 $1.6 billion for 2022. 2023.
- Net income of $770.3 million, or $6.67 per diluted share, compared with net income of $817.9 million, or $6.86 per diluted share compared with net income of $1.1 billion, or $8.96 per diluted share for 2022. 2023.
- Adjusted EBITDAX, a non-GAAP financial measure, of $1.7 $2.0 billion, compared with $1.9 $1.7 billion for 2022. Please refer 2023. Refer to *Non-GAAP Financial Measures* below for additional discussion, including our definition of adjusted EBITDAX and reconciliations to net income and net cash provided by operating activities.
- Total A 12 percent increase in total estimated net proved reserves as of December 31, 2023 December 31, 2024, increased 13 percent from December 31, 2022 December 31, 2023, to 604.9 678.3 MMBOE, of which, 58 62 percent were liquids (oil and NGLs) and 56 60 percent were proved developed reserves. The increase primarily consisted of the acquisition of 103.2 MMBOE of estimated net proved reserves in the Uinta Basin and revisions of previous estimates of 113.9 74.7 MMBOE related to infill reserves in both our South Texas and Midland Basin programs, partially offset by 55.5 62.4 MMBOE of production during 2023. 2024 and the removal of 30.5 MMBOE of certain net proved undeveloped reserves cases that are no longer expected to be developed within the five-year period from initial booking, as a result of the reallocation of capital to include our Uinta Basin assets. Our proved reserve life index increased to remained flat at 10.9 years as of December 31, 2023 December 31, 2024, compared with 10.1 years as of December 31, 2022. Please refer and 2023. Refer to *Reserves* in Part I, Items 1 and 2 of this report for additional discussion. The standardized measure of discounted future net cash flows was $7.3 billion as of December 31, 2024, compared with $6.3 billion as of December 31, 2023, compared with $10.0 billion as of December 31, 2022, which was a decrease an increase of 37 16 percent year-over-year primarily driven by the Uinta Basin Acquisition, partially offset by decreases in oil and gas benchmark commodity prices during 2023. Please refer 2024. Refer to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Operational Activities. During 2023, 2024, successful operational execution resulted in drove strong well performance in the RockStar and Sweetie Peck areas of capital efficiency across our Midland Basin position, and allowed us to maximize capital efficiency. Our South Texas program benefited from continued successful delineation and development of the Austin Chalk formation in addition to sustained strong performance of our Eagle Ford shale wells. asset portfolio. Our continued success in both our Midland Basin and South Texas programs is attributable to our top-tier assets and technical teams, and our commitment to geoscience, technology, and innovation. During the fourth quarter of 2024, we began integrating our Uinta Basin assets where we focused on delineation and development.

In our Midland Basin program, we averaged three four drilling rigs and one completion crew during 2023. We added a fourth drilling rig at the end of the third quarter to begin drilling on our newly acquired Klondike acreage. We drilled 54 gross (37 net) wells, completed 64 gross (54 net) wells, and acquired additional working interests in five net wells during 2023. 2024. Average net daily equivalent production volumes decreased increased year-over-year by seven percent to 75.4 80.5 MBOE. Costs incurred during 2023 2024 totaled $768.1

$720.9 million, or 62 21 percent, of our total 2023 2024 costs incurred. Drilling and completion activities focused on developing formations within our RockStar, and Sweetie Peck, positions in the Midland Basin were focused primarily on developing the Spraberry and Wolfcamp formations. Klondike assets.

In our South Texas program, we averaged two drilling rigs and one completion crew during 2023. We drilled 46 gross (46 net) wells and completed 38 gross (37 net) wells during 2023. 2024. Average net daily equivalent production volumes increased year-over-year by 20 six percent to 76.7 81.0 MBOE. Costs incurred during 2023 2024 totaled $423.5 $478.3 million, or 34 14 percent, of our total 2023 2024 costs incurred. Drilling and completion activities in South Texas during 2023 were primarily focused on delineating and developing the Austin Chalk formation.

In our Uinta Basin program, we averaged three drilling rigs and one completion crew during the fourth quarter of 2024. Average net daily equivalent production volumes totaled 36.1 MBOE for the fourth quarter of 2024, or 9.1 MBOE if calculated over the full year 2024. Costs incurred during 2024 totaled $2.3 billion, or 65 percent, of our total 2024 costs incurred, of which, over $2.1 billion related to acquisition costs. Drilling and completion activities primarily focused on delineating and developing the Lower Green River and Wasatch formations.

The table below provides a summary of changes in our drilled but not completed well count and current year drilling, completion, and acquisition activity in our operated programs for the year ended December 31, 2023 December 31, 2024:

	Midland Basin		Midland Basin		South Texas (1)	Total		Midland Basin		South Texas (1)	Uinta Basin		Total		
	Gross	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2022															
Wells drilled but not completed at December 31, 2023															
Drilled but not completed wells acquired (2)															
Wells drilled															
Wells completed															
Wells acquired (2)															
Wells acquired (2)															
Wells acquired (2)															
Wells drilled but not completed at December 31, 2023															
Wells drilled but not completed at December 31, 2024															
Wells drilled but not completed at December 31, 2024															
Wells drilled but not completed at December 31, 2024															

Note: Amounts may not calculate due to rounding.

(1) As of December 31, 2022 December 31, 2023, and 2023, 2024, the drilled but not completed well count included nine gross (nine net) wells that were not included in our five-year development plan, eight of which were in the Eagle Ford shale.

(2) Amount relates to additional working interests We acquired in these drilled but not completed wells as part of the Uinta Basin Acquisition on October 1, 2024. All drilling and completion activity presented in the table above for the Uinta Basin occurred during the year ended December 31, 2023. fourth quarter of 2024. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and the definition of the Uinta Basin Acquisition.

Costs Incurred. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	For the Year Ended December 31, 2023 2024	
	(in millions)thousands)	
Development costs	$	931.8 1,196,542
Exploration costs		172.6 170,297
Acquisitions		
Proved properties		65.0 1,622,192
Unproved properties		65.6 514,647
Total, including asset retirement obligations (1)	$	1,235.0 3,503,678

(1) Please refer Refer to the caption *Costs Incurred* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Production Results. The table below presents the disaggregation of our net production volumes by product type for each of our assets for the year ended December 31, 2023 December 31, 2024:

	Midland Basin		Midland Basin		South Texas		Total	Midland Basin		South Texas		Uinta Basin		Total
Net production volumes:														
Oil (MMBbl)														
Oil (MMBbl)														
Oil (MMBbl)														
Gas (Bcf)														
NGLs (MMBbl)														
Equivalent (MMBOE)														
Average net daily equivalent (MBOE per day)														
Relative percentage	Relative percentage 50 %		50 %			100 %	Relative percentage 47 %		48 %		5 %		100 %	

Note: Amounts may not calculate due to rounding.

Net equivalent production increased five 12 percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, comprised of a 20 percent increase from our South Texas assets, partially offset by a increases of seven percent decrease and six percent from our Midland Basin and South Texas assets, respectively, and 3.3 MMBOE of production during the fourth quarter of 2024 from our Uinta Basin assets. Please refer Refer to *Overview of Selected Production and Financial Information, Including Trends* and *Comparison of Financial Results and Trends Between 2024 and 2023 and Between 2023 and 2022 and Between 2022 and 2021* below for additional discussion of production.

Acquisition Activity. During 2023, we acquired approximately 20,000 net acres of oil and gas properties in Dawson and northern Martin counties, Texas. Additionally, in the Midland Basin, we added approximately 9,100 net acres through organic leasing activity, we completed an asset exchange, and we acquired additional working interests in certain wells. Please refer to *Note 16 – Acquisitions* in Part II, Item 8 of this report for additional discussion.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effect of net derivative settlements. While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location and transportation differentials, and contracted pricing benchmarks for these products.

The following table summarizes commodity price data, as well as the effect of net derivative settlements, for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021: 2022:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
Oil (per Bbl):			
Average NYMEX contract monthly price			
Average NYMEX contract monthly price			
Average NYMEX contract monthly price			
Realized price			
Effect of oil net derivative settlements			
Gas:			
Gas:			
Gas:			
Average NYMEX monthly settle price (per MMBtu)			
Average NYMEX monthly settle price (per MMBtu)			
Average NYMEX monthly settle price (per MMBtu)			
Realized price (per Mcf)			
Effect of gas net derivative settlements (per Mcf)			
NGLs (per Bbl):			
NGLs (per Bbl):			
NGLs (per Bbl):			

Average OPIS price (1)
Average OPIS price (1)
Average OPIS price (1)
Realized price
Effect of NGL net derivative settlements

(1) Effective January 1, 2023, average OPIS price per barrel of NGL, historical or strip, assumes a composite barrel product mix of 42% Ethane, 28% Propane, 6% Isobutane, 11% Normal Butane, and 13% Natural Gasoline. For periods prior to 2023, average OPIS price per barrel of NGL, historical or strip, assumed a composite barrel product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline. These product mixes represent the industry standard composite barrel for the respective periods presented and do not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

Oil prices in 2023 decreased compared with 2022 and increased compared with 2021. Gas and NGL prices in 2023 decreased compared with both 2022 and 2021. Given the uncertainty surrounding global financial markets, production output from OPEC+, global shipping channel constraints and disruptions, instability in the Middle East, economic and trade sanctions associated with the wars between Russia and Ukraine and Israel and Hamas, changes in oil inventory in storage, and the potential impacts of these issues on global commodity and financial markets, we expect benchmark prices for oil, gas, and NGLs to remain volatile for the foreseeable future, and we cannot reasonably predict the timing or likelihood of any future impacts that may result, which could include further inflation, supply chain disruptions, fluctuations in interest rates, and industry-specific impacts. In addition to supply and demand fundamentals, as

As global commodities, the prices for oil, gas, and NGLs are affected by real or perceived geopolitical risks in various regions of the world, as well as the relative strength of the United States dollar compared to other currencies. Given the uncertainty surrounding global financial markets, production output from OPEC+, global shipping channel constraints and disruptions, fluctuations in oil and gas demand from China, War and Geopolitical Instability, changes in global oil inventory in storage, tariffs or trade restrictions, and the potential impacts of these issues on global commodity markets, we expect benchmark prices for oil, gas, and NGLs to remain volatile for the foreseeable future, and we cannot reasonably predict the timing or likelihood of any future impacts that may result, which could include inflation, supply chain disruptions, fluctuations in interest rates, and industry-specific impacts. Our realized prices at local sales points may also be affected by infrastructure capacity in the areas of our operations and beyond.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs as of February 8, 2024 January 31, 2025, and December 31, 2023 December 31, 2024:

	As of February 8, 2024	As of December 31, 2023
	As of January 31, 2025	**As of December 31, 2024**
NYMEX WTI oil (per Bbl)		
NYMEX Henry Hub gas (per MMBtu)		
OPIS NGLs (per Bbl)		

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives, and decisions regarding entering into commodity derivative contracts are overseen by a financial risk management committee consisting of certain senior executive officers and finance personnel. We make

decisions about the amount of our expected production that we cover by derivatives based on the amount of debt on our balance sheet, the level of capital commitments and long-term obligations we have in place, and the terms and futures prices that are made available by our approved counterparties. With our current commodity derivative contracts, we believe we have partially reduced our exposure to volatility in commodity prices and basis differentials in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor below which we are insulated from further price decreases. Please refer Refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report and to *Commodity Price Risk* in *Overview of Liquidity and Capital Resources* below for additional information regarding our oil, gas, and NGL derivatives.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended December 31, 2023 December 31, 2024, and the preceding three quarters:

	For the Three Months Ended								
	December 31,	**December 31,**	**September 30,**	**June 30,**	**March 31,**	**December 31,**	**September 30,**	**June 30,**	**March 31,**
				2023			**2024**		
		(in millions)							
		(in millions)							
		(in millions)							
Production (MMBOE)									
Oil, gas, and NGL production revenue									
Oil, gas, and NGL production expense									
Depletion, depreciation, amortization, and asset retirement obligation liability accretion									

Depletion, depreciation, and amortization
Exploration
General and administrative
Net income

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended								
	December 31,	December 31,	September 30,	June 30,	March 31,	December 31,	September 30,	June 30,	March 31,
			2023				2024		
Average net daily equivalent production (MBOE per day)									
Lease operating expense (per BOE)									
Transportation costs (per BOE)									
Production taxes as a percent of oil, gas, and NGL production revenue	Production taxes as a percent of oil, gas, and NGL production revenue 4.6 %	4.3 %	4.3 %	4.7 %	Production taxes as a percent of oil, gas, and NGL production revenue 4.1 %	4.6 %	4.3 %	4.5 %	
Ad valorem tax expense (per BOE)									
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)									
Depletion, depreciation, and amortization (per BOE)									
General and administrative (per BOE)									

Note: Amounts may not calculate due to rounding.

Overview of Selected Production and Financial Information, Including Trends

		For the Years Ended December 31,				For the Years Ended December 31,			Amount Change Between		Perce	
			2023		2022		2021		2023/2022	2022/2021	2023/2022	
			2024		2023		2022		2024/2023	2023/2022	2024/2023	
Net production volumes: (1)												
Oil (MMBbl)												
Oil (MMBbl)												
Oil (MMBbl)		23.8	24.0	24.0	27.9	27.9	(0.2)	(0.2)	(4.0)	(4.0)	(1)	(1)%	(14)%
Gas (Bcf)	Gas (Bcf)	132.4	125.9	125.9	108.4	108.4	6.4	6.4	17.6	17.6	5	5 %	16 %
NGLs (MMBbl)	NGLs (MMBbl)	9.7	8.0	8.0	5.4	5.4	1.7	1.7	2.6	2.6	21	21 %	49 %
Equivalent (MMBOE)	Equivalent (MMBOE)	55.5	53.0	53.0	51.4	51.4	2.5	2.5	1.6	1.6	5	5 %	3 %
Average net daily production: (1)												
Oil (MBbl per day)												
Oil (MBbl per day)												
Oil (MBbl per day)		65.1	65.7	65.7	76.5	76.5	(0.6)	(0.6)	(10.8)	(10.8)	(1)	(1)%	(14)%

Gas (MMcf per day)	Gas (MMcf per day)	362.7	345.0	345.0	296.9	296.9	17.6	17.6	48.1	48.1	5	5 %	16 %	
NGLs (MBbl per day)	NGLs (MBbl per day)	26.4	21.9	21.9	14.7	14.7	4.5	4.5	7.2	7.2	21	21 %	49 %	
Equivalent (MBOE per day)	Equivalent (MBOE per day)	152.0	145.1	145.1	140.7	140.7	6.9	6.9	4.4	4.4	5	5 %	3 %	
Oil, gas, and NGL production revenue (in millions): (1)														
Oil production revenue														
Oil production revenue														
Oil production revenue		$1,813.8	$	$ 2,270.1	$	$1,891.8	$	$(456.3)	$	$ 378.2	(20)	(20)%	20 %	$2,187.5 $
Gas production revenue	Gas production revenue	327.9	790.9	790.9	525.5	525.5	(463.0)	(463.0)	265.4	265.4	(59)	(59)%	51 %	
NGL production revenue	NGL production revenue	222.2	285.0	285.0	180.6	180.6	(62.7)	(62.7)	104.3	104.3	(22)	(22)%	58 %	
Total oil, gas, and NGL production revenue	Total oil, gas, and NGL production revenue	$2,363.9	$	$ 3,345.9	$	$2,597.9	$	$(982.0)	$	$ 748.0	(29)	(29)%	29 %	Total oil, productio
Oil, gas, and NGL production expense (in millions): (1)														
Lease operating expense														
Lease operating expense														
Lease operating expense		$ 284.8	$	$ 266.5	$	$ 225.5	$	$ 18.3	$	$ 41.0	7	7 %	18 %	$ 319.0 $
Transportation costs	Transportation costs	136.2	150.0	150.0	139.4	139.4	(13.8)	(13.8)	10.6	10.6	(9)	(9)%	8 %	
Production taxes	Production taxes	105.1	162.6	162.6	121.1	121.1	(57.5)	(57.5)	41.5	41.5	(35)	(35)%	34 %	
Ad valorem tax expense	Ad valorem tax expense	37.4	41.7	41.7	19.4	19.4	(4.3)	(4.3)	22.3	22.3	(10)	(10)%	115 %	
Total oil, gas, and NGL production expense	Total oil, gas, and NGL production expense	$ 563.5	$	$ 620.9	$	$ 505.4	$	$ (57.4)	$	$ 115.5	(9)	(9)%	23 %	Total oil, productio
Realized price:														
Oil (per Bbl)														
Oil (per Bbl)														
Oil (per Bbl)		$ 76.28	$	$ 94.67	$	$ 67.72	$	$(18.39)	$	$ 26.95	(19)	(19)%	40 %	$ 74.49 $
Gas (per Mcf)	Gas (per Mcf)	$ 2.48	$	$ 6.28	$	$ 4.85	$	$ (3.80)	$	$ 1.43	(61)	(61)%	29 %	Gas (per M
NGLs (per Bbl)	NGLs (per Bbl)	$ 23.02	$	$ 35.66	$	$ 33.67	$	$(12.64)	$	$ 1.99	(35)	(35)%	6 %	NGLs (per
Per BOE	Per BOE	$ 42.60	$	$ 63.18	$	$ 50.58	$	$(20.58)	$	$ 12.60	(33)	(33)%	25 %	Per BOE
Per BOE data: (1)														
Oil, gas, and NGL production expense:														
Oil, gas, and NGL production expense:														
Oil, gas, and NGL production expense:														
Lease operating expense														
Lease operating expense														
Lease operating expense		$ 5.13	$	$ 5.03	$	$ 4.39	$	$ 0.10	$	$ 0.64	2	2 %	15 %	$ 5.11 $
Transportation costs	Transportation costs	2.46	2.83	2.83	2.71	2.71	(0.37)	(0.37)	0.12	0.12	(13)	(13)%	4 %	
Production taxes	Production taxes	1.89	3.07	3.07	2.36	2.36	(1.18)	(1.18)	0.71	0.71	(38)	(38)%	30 %	
Ad valorem tax expense	Ad valorem tax expense	0.67	0.79	0.79	0.38	0.38	(0.12)	(0.12)	0.41	0.41	(15)	(15)%	108 %	
Total oil, gas, and NGL production expense (1)	Total oil, gas, and NGL production expense (1)	$ 10.16	$	$ 11.72	$	$ 9.84	$	$ (1.56)	$	$ 1.88	(13)	(13)%	19 %	Total oi produc

Depletion, depreciation, amortization, and asset retirement obligation liability accretion		$ 12.44		$ 11.40		$ 15.08			$ 1.04			$ (3.68)			9 %		(24) %		
Depletion, depreciation, and amortization		$ 12.97		$ 12.44		$ 11.40			$ 0.53			$ 1.04			4 %		9 %		
General and administrative	General and administrative	$ 2.18	$	$ 2.16	$	$ 2.18	$		$ 0.02	$		$ (0.02)	1		1 %		(1)%		General ar
Net derivative settlement gain (loss) (2)	Net derivative settlement gain (loss) (2)	$ 0.49	$	$ (13.42)	$	$ (14.58)	$		$ 13.91	$		$ 1.16	104		104 %		8 %		Net derivat gain (loss)
Earnings per share information (in thousands, except per share data): (3)																			
Basic weighted-average common shares outstanding																			
Basic weighted-average common shares outstanding																			
Basic weighted-average common shares outstanding		118,678	122,351	122,351	119,043		119,043	(3,673)		(3,673)	3,308		3,308	(3)		(3)%		3 %	
Diluted weighted-average common shares outstanding	Diluted weighted-average common shares outstanding	119,240	124,084	124,084	123,690		123,690	(4,844)		(4,844)	394		394	(4)		(4)%		— %	
Basic net income per common share	Basic net income per common share	$ 6.89	$	$ 9.09	$	$ 0.30	$		$ (2.20)	$		$ 8.79	(24)		(24)%		2,930 %		Basic net i common s
Diluted net income per common share	Diluted net income per common share	$ 6.86	$	$ 8.96	$	$ 0.29	$		$ (2.10)	$		$ 8.67	(23)		(23)%		2,990 %		Diluted net common s

(1) Amounts and percentage changes may not calculate due to rounding.

(2) Net derivative settlements for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, are included within the net derivative (gain) loss line item in the accompanying consolidated statements of operations ("accompanying statements of operations").

(3) Please refer Refer to *Note 9 – Earnings Per Share* in Part II, Item 8 of this report for additional discussion.

Average net daily equivalent production for the year ended December 31, 2023 December 31, 2024, increased five 12 percent compared with 2022, 2023, as a result of an increased number of completions. completions, strong well performance, and production from our Uinta Basin assets during the fourth quarter of 2024. Oil production as a percentage of total production increased to 47 percent in 2024 from 43 percent in 2023, as a result of increased oil production from both our Midland Basin and South Texas assets, in addition to oil production from our Uinta Basin assets. In 2024, 2025, we expect total production volumes to increase slightly compared with 2023, and we expect a slight increase in oil as a percentage of total production. Please refer production to each increase compared with 2024. Refer to *Comparison of Financial Results and Trends Between 2024 and 2023 and Between 2023 and 2022 and Between 2022 and 2021* below for additional discussion.

We present certain information on a per BOE basis in order to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis and discussion.

Our realized price on a per BOE basis decreased $20.58 remained flat for the year ended December 31, 2023 December 31, 2024, compared with 2022, as 2023, primarily because a result of 24 percent increase in oil production was offset by decreases in oil and gas and NGL benchmark commodity prices. For the year years ended December 31, 2023 December 31, 2024, and 2023, we recognized a net gain gains on the settlement of our commodity derivative contracts of $1.10 per BOE and $0.49 per BOE, compared to a net loss of $13.42 per BOE for the same period in 2022. respectively.

LOE on a per BOE basis increased two percent remained flat for the year ended December 31, 2023 December 31, 2024, compared with 2022, primarily driven by 2023, as increases in labor costs. costs and certain other operating costs were offset by an increase in total net equivalent production and a decrease in workover expense due to the timing of activity. For 2024, 2025, we expect LOE on a per BOE basis to increase, compared with 2023, primarily 2024, as our product mix continues to shift towards more oil production with our Uinta Basin assets, and as a result of expected increases in certain operating costs associated with both our Midland Basin and South Texas assets. We anticipate volatility in LOE on a per BOE basis as a result of changes in total production, changes in our overall production mix, timing of workover projects, inflation, changes in service provider costs, and industry activity, all of which affect total LOE.

Transportation costs on a per BOE basis decreased 13 increased nine percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, as 2023. This increase was due to a result of the expiration of a long-term contract six percent increase in NGL production from our South Texas on June 30, 2023. assets and 3.3 MMBOE of production from our Uinta Basin assets, both of which incur higher transportation costs than our Midland Basin assets. In general, we expect total transportation costs to fluctuate relative to changes in gas and NGL production from our South Texas assets and oil production from our Uinta Basin assets, where we incur a majority of our transportation costs. For 2024, 2025, we expect transportation costs on a per BOE basis to decrease increase, compared with 2023, 2024, as a result of the expiration addition of the long-term contract in South Texas previously discussed. our Uinta Basin assets.

Production tax expense on a per BOE basis for the year ended December 31, 2023 December 31, 2024, decreased 38 two percent compared with 2022, 2023, primarily as a result of decreases a decrease in the realized prices. price of gas. Our overall production tax rate was 4.4 4.3 percent and 4.9 4.4 percent for the years ended December 31, 2023 December 31, 2024, and 2022, 2023, respectively. We expect that our Uinta Basin assets will incur a lower production tax rate compared to our Midland Basin and South Texas assets. We generally expect production tax expense to correlate with oil, gas, and NGL production revenue on an absolute and a per BOE and absolute basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax expense that we recognize.

Ad valorem tax expense on a per BOE basis decreased 15 16 percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, as we were positively impacted by a property tax relief bill that provided for a one-time benefit during 2023. result of changes to the assessed values of our producing properties due to decreased commodity price assumptions used in the current year valuation, and increased net equivalent production. We anticipate volatility in ad valorem tax expense on a per BOE and absolute basis as the valuation of our producing properties changes, which is generally driven by fluctuations in commodity prices, and can be impacted by changes in tax laws.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion amortization ("DD&A") expense on a per BOE basis increased nine four percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, due to inflation and higher drilling and completion activity a shift in the production mix to our Uinta Basin assets. Our Midland Basin partially offset by increased production related to and Uinta Basin assets have higher DD&A rates than our South Texas assets, which have a lower DD&A rate than our Midland Basin assets. For 2024, 2025, we expect DD&A expense per BOE to remain flat, and DD&A expense on an absolute basis to increase, slightly, compared with 2023, 2024, primarily as a result of expected increased production. production resulting from the addition of our Uinta Basin assets, and a shift in our production mix. Our DD&A rate fluctuates as a result of changes in our production mix, changes in our total estimated proved reserve volumes, changes in capital allocation, impairments, acquisition and divestiture activity, and carrying cost funding and sharing arrangements with third parties.

General and administrative ("G&A") expense on a per BOE basis remained relatively flat increased two percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, primarily as a result of increases in certain G&A expenses resulting from the Uinta Basin Acquisition and increased compensation expense, partially offset by a 12 percent increase in average net equivalent production. For 2025, we expect G&A expense on an absolute basis to increase, compared with 2024, primarily as a result of an increase in employee headcount as a result of the Uinta Basin Acquisition and expected increases in compensation expense. We expect G&A expense on a per BOE basis to remain relatively flat, compared with 2024, as the expected increases in G&A expense on an absolute basis related are expected to compensation expense was be mostly offset by an increase increases in production volumes. production. Certain components of G&A expense, and G&A expense on a per BOE basis, are impacted by

the Company's full year performance against performance targets established at the beginning of the year and, therefore, are subject to variability. For Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for the definition of the Uinta Basin Acquisition.

Refer to *Comparison of Financial Results and Trends Between 2024 we expect G&A expense per BOE to remain flat, and G&A expense on an absolute basis to increase compared with 2023 primarily as a result and Between 2023 and 2022* for additional discussion of expected increases in compensation expense due to inflation. operating expenses.

Please refer **Comparison of Financial Results and Trends Between 2024 and 2023 and Between 2023 and 2022**

Refer to *Comparison of Financial Results and Trends Between 2023 and 2022 and Between 2022 and 2021* in *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of our 2023 Annual Report on Form 10-K, filed with the SEC on February 22, 2024, for additional a detailed discussion of operating expenses.

Comparison certain comparisons of Financial Results our financial results and Trends Between 2023 and 2022 and Between 2022 and 2021

Please refer trends for the year ended December 31, 2023, compared with the year ended December 31, 2022. Refer to *Comparison of Financial Results and Trends Between 2022 and 2021 and Between 2021 and 2020* in

Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2022 Annual Report on Form 10-K, filed with the SEC on February 23, 2023, for a detailed discussion of certain comparisons of our financial results and trends for the year ended December 31, 2022, compared with the year ended December 31, 2021.

Average net daily equivalent production, production revenue, and production expense

The following table presents the changes in our average net daily equivalent production, oil, gas, and NGL production revenue, and oil, gas, and NGL production expense, by area, between the years ended December 31, 2024, and 2023:

	Average Net Equivalent Production Increase	Oil, Gas, and NGL Production Revenue Increase	Oil, Gas, and NGL Production Expense Increase (Decrease)
	(MBOE per day)	(in millions)	(in millions)
Midland Basin	5.1	$ 43.1	$ 6.6
South Texas	4.3	60.2	(7.9)
Uinta Basin	9.1	204.0	74.7
Total	18.5	$ 307.4	$ 73.4

Note: Amounts may not calculate due to rounding.

Average net daily equivalent production volumes for the year ended December 31, 2024, increased 12 percent compared with 2023, comprised of a seven percent increase from our Midland Basin assets, a six percent increase from our South Texas assets, and 9.1 MBOE of production from our Uinta Basin assets. As a result of decreases in benchmark oil and gas prices, realized prices for oil and gas decreased two percent and 27 percent, respectively, while the realized price for NGLs remained flat. The 13 percent increase in oil, gas, and NGL production revenue is primarily a result of the increase in average net daily equivalent production volumes. Oil, gas, and NGL production expense for the year ended December 31, 2024, increased 13 percent compared with 2023, as activity related to our Uinta Basin assets contributed to increases in transportation costs, LOE, and production tax expense.

The following table presents the changes in our average net daily equivalent production, oil, gas, and NGL production revenue, and oil, gas, and NGL production expense, by area, between the years ended December 31, 2023, and 2022:

	Net Equivalent Production Increase (Decrease)	Production Revenue Decrease	Production Expense Decrease

	Average Net Equivalent Production Increase (Decrease)		Oil, Gas, and NGL Production Revenue Decrease	Oil, Gas, and NGL Production Expense Decrease			
	(MBOE per day)	(MBOE per day)		(in millions)		(MBOE per day)	(in millions)
Midland Basin							
South Texas							
Total							

Note: Amounts may not calculate due to rounding.

Average net daily equivalent production volumes for the year ended December 31, 2023, increased five percent compared with 2022, comprised of a 20 percent increase from our South Texas assets, partially offset by a seven percent decrease from our Midland Basin assets. As a result of decreases in benchmark commodity prices, realized prices for oil, gas, and NGLs decreased 19 percent, 61 percent, and 35 percent, respectively, resulting in a 29 percent decrease in oil, gas, and NGL production revenue. Oil, gas, and NGL production expense for the year ended December 31, 2023, decreased nine percent compared with 2022, primarily driven by decreases in production taxes and transportation costs, partially offset by an increase in LOE.

The following table presents the changes in our average net daily equivalent production, production revenue, and production expense, by area, between the years ended December 31, 2022, and 2021:

	Net Equivalent Production Increase (Decrease)		Production Revenue Increase		Production Expense Increase
	(MBOE per day)		(in millions)		(in millions)
Midland Basin	(13.0)	$	222.0	$	55.5
South Texas	17.3		526.0		60.0
Total	4.4	$	748.0	$	115.5

Note: Amounts may not calculate due to rounding.

Average net daily equivalent production volumes for the year ended December 31, 2022, increased three percent compared with 2021, comprised of a 37 percent increase from our South Texas assets, partially offset by a 14 percent decrease from our Midland Basin assets. As a result of increases in benchmark commodity prices, realized prices for oil, gas, and NGLs increased 40 percent, 29 percent, and six percent, respectively, resulting in a 29 percent increase in oil, gas, and NGL production revenue. Oil, gas, and NGL production expense for the year ended December 31, 2022, increased 23 percent, compared with 2021, primarily as a result of increased production taxes and LOE.

Please refer Refer to *Overview of Selected Production and Financial Information, Including Trends* above for additional discussion, including discussion of trends on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion amortization

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
		(in millions)	
		(in millions)	
		(in millions)	
Depletion, depreciation, amortization, and asset retirement obligation liability accretion			
Depletion, depreciation, and amortization			

DD&A expense for the year ended December 31, 2024, increased 17 percent compared with 2023, primarily as a result of a combination of increased average net daily equivalent production, including the addition of production from our Uinta Basin assets during the fourth quarter of 2024, and a shift in production mix to our Uinta Basin assets. Our Midland Basin and Uinta Basin assets have higher DD&A rates than our South Texas assets. DD&A expense for the year ended December 31, 2023, increased 14 percent compared with 2022, primarily as a result of inflation and a five percent increase in average net daily equivalent production volumes, partially offset by a shift in production mix due to higher activity in our South Texas assets, which have a lower DD&A rate than our Midland Basin assets. DD&A expense for the year

ended December 31, 2022, decreased 22 percent, compared with 2021, primarily as a result of increased estimated net proved reserves at the end of 2021 and during 2022, and increased activity in our Austin Chalk program. Please refer Refer to *Overview of Selected Production and Financial Information, Including Trends* above for discussion of DD&A expense on a per BOE basis.

Exploration

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022

	(in millions)
	(in millions)
	(in millions)
Geological, geophysical, and other expenses	
Overhead	
Total	

Exploration expense increased eight percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, primarily due as a result of an increase in geological and geophysical expenses related to increases in both overhead and geological, geophysical, and other expenses. our Uinta Basin assets. Exploration expense fluctuates based on actual geological and geophysical studies we perform within an exploratory area, exploratory dry hole expense incurred, and changes in the amount of allocated overhead.

Impairment

	For the Years Ended December 31,		
	2023	2022	2021
		(in millions)	
Impairment	$ —	$ 7.5	$ 35.0

No impairment expense was recorded for the year ended December 31, 2023, as a result of fewer actual and anticipated lease expirations and title defects. Impairment expense recorded during the years ended December 31, 2022, and 2021, consisted of unproved property abandonments and impairments related to actual and anticipated lease expirations, as well as actual and anticipated losses of acreage due to title defects, changes in development plans, and other inherent acreage risks.

We expect proved property impairments to occur more frequently in periods of declining or depressed commodity prices, and that the frequency of unproved property abandonments and impairments will fluctuate with the timing of lease expirations or title defects, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, unsuccessful exploration activities, and downward engineering revisions may result in proved and unproved property impairments.

Reserve estimates and related impairments of proved and unproved properties are difficult to predict in a volatile price environment. If commodity prices for the products we produce decline as a result of supply and demand fundamentals associated with geopolitical or macroeconomic events, we may experience proved and unproved property impairments in the future. Future impairments of proved and unproved properties are difficult to predict; however, based on our commodity price assumptions as of February 8, 2024, we do not expect any material oil and gas property impairments in the first quarter of 2024 resulting from commodity price impacts.

Please refer to *Critical Accounting Estimates* below and *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for additional discussion.

General and administrative

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
		(in millions)	
		(in millions)	
		(in millions)	
General and administrative			

G&A expense increased six 14 percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, primarily as a result of increases in certain G&A expenses resulting from the Uinta Basin Acquisition and increased compensation expense. Please refer Refer to *Overview of Selected Production and Financial Information, Including Trends* above for discussion of G&A expense, including G&A expense on a per BOE basis. basis, and to

Note 17 – Acquisitions in Part II, Item 8 of this report for the definition of the Uinta Basin Acquisition.

Net derivative (gain) loss

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
		(in millions)	
		(in millions)	
		(in millions)	
Net derivative (gain) loss			

Net derivative (gain) loss is a result of changes in fair values associated with fluctuations in the forward price curves for the commodities underlying our outstanding derivative contracts and the monthly cash settlements of our derivative positions during the period. We expect increases in benchmark commodity prices to result in net derivative losses, and decreases in benchmark commodity prices to result in net derivative gains, as measured against our derivative contract prices. Please refer Refer to *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Other operating expense, net

	For the Years Ended December 31,		
	2023	2022	2021
	(in millions)		
Other operating expense, net	$ 20.6	$ 3.5	$ 46.1

Other operating expense, net, recorded in 2023 and 2021, primarily related to legal matters.

Interest expense

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in millions)		
	(in millions)		
	(in millions)		
Interest expense			

Interest expense decreased 24 increased 54 percent for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, as a result of the reduction in the aggregate principal amount issuance of our 2029 Senior Notes through various transactions and 2032 Senior Notes during 2024, an increase in 2022, including interest expense associated with borrowings under our revolving credit facility, and a $9.0 million fee that was paid to secure firm commitments for up to $1.2 billion of senior unsecured 364-day bridge term loans ("Bridge Facility") in connection with the redemption Uinta Basin Acquisition. We did not draw on the Bridge Facility, and after issuance of our 2024 the 2029 Senior Notes and 2032 Senior Notes on February 14, 2022 July 25, 2024, we terminated the Bridge Facility, and the redemption of our 2025 Senior Secured Notes on June 17, 2022. associated fees were recognized as interest expense. Total interest expense can vary based on the amount of our outstanding fixed-rate debt securities, fluctuations in the amount of capitalized interest as a result of the timing of the development of our wells in progress, and due to the timing and amount of borrowings under our revolving credit facility. Please refer Refer to *Overview of Liquidity and Capital Resources* below, *Significant Developments in 2024* in Part I, Items 1 and 2 for the definitions of 2029 Senior Notes and 2032 Senior Notes, and to *Note 5 – Long-Term Debt* and *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion including the definition of Senior Notes and 2025 Senior Secured Notes. definitions.

Interest income

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in millions)		
	(in millions)		
	(in millions)		
Interest income			

Interest income increased for the year ended December 31, 2023 December 31, 2024, compared with 2022, 2023, primarily due to an increase in average interest rates on our interest-bearing cash equivalents and maintaining a higher average balance of our interest-bearing cash and cash equivalents balance as a result of the issuance of our 2029 Senior Notes and 2032 Senior Notes during 2023. the third quarter of 2024 resulting in excess cash prior to the Closing Date of the Uinta Basin Acquisition. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and definitions.

Loss on extinguishment of debt

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in millions)		
	(in millions)		
	(in millions)		
Loss on extinguishment of debt			

The redemption of our 2025 Senior Secured Notes during 2022 resulted in a net loss on extinguishment of debt of

$67.2 $67.2 million, which included $33.5 million of premium paid, $26.3 million of accelerated expense recognition of the unamortized debt discount, and $7.4 million of accelerated expense recognition of the unamortized deferred financing costs. Please refer Refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion including and the definition of 2025 Senior Secured Notes.

Income tax expense

	For the Years Ended December 31,					
	2023	2022	2021			
	2024	2023	2022			
	(in millions, except tax rate)					
	(in millions, except tax rate)					
	(in millions, except tax rate)					
Income tax expense						
Effective tax rate	Effective tax rate 10.5 %	20.3 %	21.5 %	Effective tax rate 20.3 %	10.5 %	20.3 %

Our effective tax rate decreased for in 2023 benefited from credits claimed as the year ended December 31, 2023, compared with 2022, primarily due to benefits recognized as a result of the completion of a multi-year research and development ("R&D" &D") credit study conducted during 2023, partially study. Excess tax deficiencies from stock-based compensation awards offset by limits on expensing of certain covered individual's compensation, net apportionment changes and other permanent expense items reduced the release of the valuation allowance during the year ended December 31, 2023, that lowered the effective tax rate compared to no valuation benefit recognized during the year ended December 31, 2022.

The decrease in the effective tax rate for the year ended December 31, 2022, compared with 2021, primarily resulted each period presented. We benefited from the release of the a valuation allowance recorded against the derivative on certain deferred tax asset recognized assets in prior periods. As a result of the increase in income before income taxes for the year ended December 31, 2022, compared with 2021, our permanent items, including excess tax benefits from stock-based compensation and limits on expensing of certain individual's compensation, had less of an impact on the effective tax rate for the year ended December 31, 2022, compared with 2021. 2022.

During 2023, 2024, we made federal estimated tax payments of $3.0 million $25.5 million and state cash tax payments, net of $6.0 million, primarily related to Texas franchise taxes. refunds, of $1.4 million.

Enactment of proposed changes to federal income tax laws, specifically including changes in the Tax Relief for American Families and Workers Act of 2024, corporate tax rate, could have a material effect on our current tax expense, tax receivable, and deferred tax liabilities. Effective for tax years beginning after December 31, 2022, the IRA provides for a 15 percent corporate alternative minimum tax ("CAMT") on corporations with average adjusted financial statement income over $1.0 billion for any three-year period preceding the tax year. While the final proposed regulations regarding the CAMT may impact our calculation, as of the filing of this report we do not anticipate that we will become subject to the CAMT in 2025. Refer to *Overview of Liquidity and Capital Resources* below and to the *Risk Factors* section in Part 1, Item 1A of this report.

Please refer Refer to *Critical Accounting Estimates* below and *Note 4 – Income Taxes* in Part II, Item 8 of this report for further discussion.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan while continuing to meet our current financial obligations. We continue to manage the duration and level of our drilling and completion service commitments in order to maintain flexibility with regard to our activity level and capital expenditures.

Sources of Cash

We expect to fund our 2024 2025 capital expenditure expenditures and return of capital programs to be funded program with cash flows from operating activities and operations, with any remaining cash on hand. We may also use needs being funded by borrowings under our revolving credit facility or facility. Although we expect cash flows from these sources to be sufficient for 2025, we may also elect to raise funds through new debt or equity offerings or from other sources of financing. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly issued securities may have rights, preferences, or privileges senior to those of existing stockholders and bondholders. Additionally, we may enter into carrying cost and sharing arrangements with third parties for certain exploration or development programs.

During 2024, we issued our 2029 Senior Notes and 2032 Senior Notes. See below for discussion on how the net proceeds received were used, and to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Our credit ratings affect the availability of, and cost for us to borrow, additional funds. Two One major credit rating agencies agency upgraded our credit ratings during 2023, following the close of the Uinta Basin Acquisition on October 1, 2024, citing our increased size and scale, increased inventory, increased oil percentage of expected production, strong operational performance, our priority of improving our leverage metrics, our ability to consistently generate meaningful cash flows, disciplined capital spending, return and our use of capital financial derivative instruments as part of our financial risk management program. Refer to stockholders, debt redemptions during 2022, and sustained strong operational performance, including our established inventory*Note 17 – Acquisitions* in Part II, Item 8 of drilling locations in our Midland this report for the definition of the Uinta Basin and South Texas programs, all of which contribute to our strong liquidity profile. Acquisition.

All of our sources of liquidity can be affected by the general conditions of the broader economy, force majeure events, fluctuations in commodity prices, operating costs, interest rate changes, tax law changes, and volumes produced, all of which affect us and our industry.

We have no control over the market prices for oil, gas, and NGLs, although we may be able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of commodity derivative contracts as part of our commodity price financial risk management program. Commodity derivative contracts may limit the prices we receive for our oil, gas, and NGL sales if oil, gas, or NGL prices rise substantially over the price established by the commodity derivative contract. Please refer Refer to *Note 7 – Derivative*

Financial Instruments in Part II, Item 8 of this report for additional information about our commodity derivative contracts currently in place and the timing of settlement of those contracts.

Credit Agreement

Our Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of $3.0 billion. As of December 31, 2023 December 31, 2024, the borrowing base and aggregate revolving lender commitments under our Credit Agreement were $2.5 $3.0 billion and $1.25 $2.0 billion, respectively. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both our proved oil and gas properties reflected in our most recent reserve report and commodity derivative contracts, each as determined by our lender group. The next scheduled borrowing base redetermination date is April 1, 2024 scheduled to occur on April 1, 2025. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. We must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring that we maintain certain financial ratios, as set forth in the Credit Agreement. We were in compliance with all financial and non-financial covenants as of December 31, 2023 December 31, 2024, and through the filing of this report. Please refer Refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion, as well as the presentation of the outstanding balance, total amount

of letters of credit, and available borrowing capacity under the Credit Agreement as of February 8, 2024 January 31, 2025, December 31, 2023 December 31, 2024, and December 31, 2022 December 31, 2023.

Our daily weighted-average revolving credit facility balance was $56.7 million during the year ended December 31, 2024. We had no revolving credit facility borrowings during the years year ended December 31, 2023, and 2022. through the third quarter of 2024. Cash flows provided by our operating activities, proceeds received from divestitures of properties, capital markets activities including open market debt repurchases, debt redemptions, repayment of scheduled debt maturities, other financing activities, and our capital expenditures, including acquisitions, all impact the amount we borrow under our revolving credit facility.

Weighted-Average Interest and Weighted-Average Borrowing Rates

Our weighted-average interest rate includes paid and accrued interest, fees on the unused portion of the aggregate commitment amount under the Credit Agreement, letter of credit fees, the non-cash amortization of deferred financing costs, and for the periods portion of 2022 during which they were outstanding, the non-cash amortization of the discounts discount related to the 2021 Senior Secured Convertible Notes and 2025 Senior Secured Notes, each as defined in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. Our weighted-average borrowing rate includes paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021: 2022:

		For the Years Ended December 31,						
		2023	2022	2021				
		2024	2023	2022				
Weighted-average interest rate	Weighted-average interest rate	7.1 %	7.6 %	7.7 %	Weighted-average interest rate	7.6 %	7.1 %	7.6 %
Weighted-average borrowing rate	Weighted-average borrowing rate	6.4 %	6.8 %	6.8 %	Weighted-average borrowing rate	6.6 %	6.4 %	6.8 %

Our weighted-average interest rate and weighted-average borrowing rate both each increased for the year ended December 31, 2024, compared with 2023, primarily as a result of the issuance of our 2029 Senior Notes and 2032 Senior Notes during 2024, which have greater outstanding aggregate principal balances and higher interest rates compared with our other outstanding Senior Notes and our 2025 Senior Notes that we redeemed during the third quarter of 2024, and as a result of borrowings under our revolving credit facility during the fourth quarter of 2024. Our weighted-average interest rate and weighted-average borrowing rate each decreased for the year ended December 31, 2023, compared with 2022, as a result of the redemptions of our 2024 Senior Notes and 2025 Senior Secured Notes during 2022. Our weighted-average interest rate remained flat The rates disclosed in the table above for the year ended December 31, 2022 December 31, 2024, compared do not reflect the $9.0 million fee paid to secure the Bridge Facility in connection with 2021, as an increase in deferred financing costs related to the Credit Agreement was offset by a decrease in interest expense resulting from the redemption of the 2025 Senior Secured Notes. Our weighted-average borrowing rate remained flat for the year ended December 31, 2022, compared with 2021, as a result of the timing of redemptions of our Senior Notes during 2022 and 2021. Uinta Basin Acquisition.

Our weighted-average interest rate and weighted-average borrowing rate are affected by the occurrence and timing of long-term debt issuances and redemptions and the average outstanding balance on our revolving credit facility. Additionally, our weighted-average interest rate is affected by the fees paid on the unused portion of our aggregate revolving lender commitments. The rates disclosed in the above table do not reflect certain amounts associated with the repurchase or redemption of Senior Notes, such as the accelerated expense recognition of the unamortized deferred financing costs and unamortized discounts, as these amounts are netted against the associated gain or loss on extinguishment of debt. The 2021 Senior Secured Convertible Notes were retired upon maturity on July 1, 2021, the 2024 Senior Notes were redeemed on February 14, 2022, and the 2025 Senior Secured Notes were redeemed on June 17, 2022 , and the 2025 Senior Notes were redeemed on August 26, 2024. After these dates, the weighted-average interest rate was no longer affected by the non-cash amortization of deferred financing costs or, for the 2021 Senior Secured Convertible Notes and the 2025 Senior Secured Notes, the non-cash amortization of the discounts. Please refer discount.

Refer to *Significant Developments in 2024* in Part I, Items 1 and 2 for the definitions of 2029 Senior Notes and 2032 Senior Notes, and to *Note 5 – Long-Term Debt* and *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and definitions.

Uses of Cash

We use cash for the development, exploration, and acquisition of oil and gas properties; for the payment of operating and general and administrative costs, income taxes, debt obligations, including interest and early repayments or redemptions, dividends, and dividends; and for repurchases of shares of our outstanding common stock under the Stock Repurchase Program. Expenditures for the development, exploration, and acquisition of oil and gas properties are the primary use of our capital resources. During 2023, 2024, we spent

$1.1 $3.4 billion on capital expenditures and on acquisitions of proved and unproved oil and gas properties, including the acquisition of additional working interests in certain wells. properties. This amount differs from the costs incurred amount of $1.2 $3.5 billion for the year ended December 31, 2023 December 31, 2024, as costs incurred is an accrual-based amount that also includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts. Please refer Refer to *Costs Incurred* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

The amount and allocation of our future capital expenditures will depend upon a number of factors, including our cash flows from operating, investing, and financing activities, our ability to execute our development program, inflation, and the number and size of acquisitions that we complete. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital,

tax law and other regulatory changes, and the timing and results of our exploration and development activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget and guidance to assess if changes are necessary based on current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

Changes to the Internal Revenue Code ("IRC"), and federal income tax laws could increase the our corporate income tax rate and could eliminate or reduce current tax deductions, such as those for intangible drilling costs, depreciation of equipment costs, and other deductions which currently reduce our taxable income. Current The CAMT and other possible future legislation could reduce our net cash provided by operating activities over time, and could therefore result resulting in a reduction of funding available funding. Refer to *Comparison of Financial Results and Trends Between 2024 and 2023 and Between 2023 and 2022* above for the items discussed above. additional discussion.

We may from time to time repurchase shares of our common stock, or repurchase or redeem all or portions of our outstanding debt securities, for cash, through exchanges for other securities, or a combination of both. Such repurchases or redemptions may be made in open market transactions, privately negotiated transactions, tender offers, pursuant to contractual provisions, or otherwise. Any such repurchases or redemptions will depend on our business strategy, prevailing market conditions, our liquidity requirements, contractual restrictions or covenants, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

During the years ended December 31, 2023 December 31, 2024, and 2022, 2023, we repurchased and subsequently retired 6.9 1.8 million shares and 1.4 6.9 million shares, respectively, of our common stock at a cost, excluding excise taxes, commissions, and fees, of $228.0 $84.0 million and $57.2 $228.0 million, respectively. As of the filing of this report, $214.9 December 31, 2024, $500.0 million remains remained available under the Stock Repurchase Program for repurchases of our common stock through December 31, 2024 December 31, 2027. Effective January 1, 2023, shares of common stock repurchased, net of shares of common stock issued, are subject to a one percent excise tax imposed by the IRA. We recorded an immaterial paid a minimal amount of excise tax related to common stock repurchases during 2023. Please refer 2024. Refer to *Note 3 – Equity* in Part II, Item 8 of this report for discussion of the Stock Repurchase Program.

During the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, we paid $85.0 million, $71.6 million, $19.6 million, and $2.4 $19.6 million, respectively, in dividends to our stockholders. Dividends paid reflects were $0.74, $0.60, $0.16, and $0.02 $0.16 per share during the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively. During 2023, 2024, our Board of Directors approved a 20 an 11 percent increase to our fixed dividend to $0.72 $0.80 per share annually, to be paid in quarterly increments of $0.18 $0.20 per share, beginning which commenced in the first fourth quarter of 2024. We currently intend to continue paying dividends to our stockholders for the foreseeable future, subject to our future earnings, our financial condition, covenants under our Credit Agreement and indentures governing each series of our outstanding Senior Notes, and other factors that could arise. The payment and amount of future dividends remain at the discretion of our Board of Directors.

During 2022, 2024, we redeemed all of the $349.1 million of aggregate principal amount outstanding of our 2024 2025 Senior Notes. Additionally, we used a portion of the net proceeds from the 2029 Senior Notes and 2032 Senior Notes, cash on hand, and borrowings under our 2025 revolving credit facility to fund our proportionate share of the Uinta Basin Acquisition. Refer to *Significant Developments in 2024* in Part I, Items 1 and 2 for the definitions of 2029 Senior Secured Notes. Please refer Notes and 2032 Senior Notes, and to *Note 5 – Long-Term Debt* and *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and definitions.

Analysis of Cash Flow Changes Between 2024 and 2023 and Between 2023 and 2022 and Between 2022 and 2021

The following tables present changes in cash flows between the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our accompanying consolidated statements of cash flows ("accompanying statements of cash flows") in Part II, Item 8 of this report.

Operating Activities

	For the Years Ended December 31,
	For the Years Ended December 31,
	For the Years Ended December 31,
	2023
	2023
	2023
	2024
	2024
	2024
	(in millions)
	(in millions)
	(in millions)
Net cash provided by operating activities	
Net cash provided by operating activities	
Net cash provided by operating activities	

Net cash provided by operating activities increased for the year ended December 31, 2024, compared with 2023, primarily as a result of a $184.8 million increase in cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, and an increase of $62.4 million in cash received on settled derivative trades. These amounts were partially offset by an increase of $46.5 million in cash paid for G&A expense, LOE, and ad valorem taxes. Net cash provided by operating activities was also affected by the timing of payments made between us and XCL Resources related to activity occurring after the Closing Date of the Uinta Basin Acquisition. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion and definitions.

Net cash provided by operating activities decreased for the year ended December 31, 2023, compared with 2022, primarily as a result of a $937.3 million decrease in cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, and an increase of $44.5 million in cash paid for LOE and ad valorem taxes, partially offset by a decrease of $749.3 million in cash paid on settled derivative trades and a $45.5 million decrease in cash paid for interest.

Net cash provided by operating activities increased for the year ended December 31, 2022, compared with 2021, primarily as a result of an $833.2 million increase in cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, partially offset by an increase in cash paid for LOE and G&A expense of $70.7 million and an increase of $69.2 million in cash paid on settled derivative trades.

Net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements.

Investing Activities

	For the Years Ended December 31,
	For the Years Ended December 31,
	For the Years Ended December 31,
	2023
	2023
	2023
	2024
	2024
	2024
	(in millions)
	(in millions)
	(in millions)
Net cash used in investing activities	
Net cash used in investing activities	
Net cash used in investing activities	

Net cash used in investing activities increased for the year ended December 31, 2024, compared with 2023, as a result of $2.1 billion of cash paid for the Uinta Basin Acquisition and a $321.2 million increase in capital expenditures.

Net cash used in investing activities increased for the year ended December 31, 2023, compared with 2022, as a result of a $109.5 million increase in capital expenditures and $109.9 million of cash paid to acquire proved and unproved oil and gas properties in the Midland Basin, including the acquisition of additional working interests in certain wells. Please refer

Refer to *Note 16 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion of acquisition activity and the acquisition definition of proved and unproved oil and gas properties.

Net cash used in investing activities increased for the year ended December 31, 2022, compared with 2021, primarily as a result of a $205.1 million increase in capital expenditures.

Net cash used in investing activities during the years ended December 31, 2023, 2022, and 2021, was funded by net cash provided by operating activities. Uinta Basin Acquisition.

Financing Activities

	For the Years Ended December 31,
	For the Years Ended December 31,
	For the Years Ended December 31,
	2023
	2023
	2023
	2024
	2024
	2024
	(in millions)
	(in millions)
	(in millions)

Net cash used in financing activities
Net cash used in financing activities
Net cash used in financing activities
Net cash provided by (used in) financing activities
Net cash provided by (used in) financing activities
Net cash provided by (used in) financing activities

Net cash provided by financing activities increased during the year ended December 31, 2024, primarily related to net cash proceeds of $1.5 billion from the issuance of our 2029 Senior Notes and 2032 Senior Notes, and net borrowings under our revolving credit facility of $68.5 million, partially offset by $349.1 million of cash paid to redeem our 2025 Senior Notes. Additionally, we paid $86.1 million, including commission and fees, to repurchase and subsequently retire 1.8 million shares of our common stock under the Stock Repurchase Program, and paid $85.0 million of dividends to our stockholders.

Net cash used in financing activities during the year ended December 31, 2023, primarily consisted of $228.1 million of cash paid, including commission and fees, to repurchase and subsequently retire 6.9 million shares of our common stock under the Stock Repurchase Program, and $71.6 million of dividends paid to our stockholders.

Net cash used in financing activities during the year ended December 31, 2022, related to $480.2 million of cash paid, including premium, to redeem our 2025 Senior Secured Notes, and $104.8 million of cash paid to redeem our 2024 Senior Notes. Additionally, we paid $57.2 million, including commission and fees, to repurchase and subsequently retire 1.4 million shares of our common stock under the Stock Repurchase Program, $25.1 million for the net share settlement of employee stock awards, and paid $19.6 million of dividends paid to our stockholders.

During the year ended December 31, 2021, we paid $385.3 million, including net premiums, to fund the Tender Offer and the 2022 Senior Notes Redemption, and we received net cash proceeds of $392.8 million from the issuance of our 2028 Senior Notes. Additionally, we paid $65.5 million to retire our 2021 Senior Secured Convertible Notes and had net repayments under our revolving credit facility of $93.0 million.

Please refer Refer to *Note 3 – Equity* in Part II, Item 8 of this report for additional discussion of our Stock Repurchase Program and *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion and definitions related to our debt transactions.

Interest Rate Risk

We are exposed to market and credit risk due to the floating interest rate associated with any outstanding balance on our revolving credit facility. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the revolving credit facility's fair value but will not affect results of operations or cash flows. Conversely, for the portion of the revolving credit facility that has a floating interest rate, interest rate changes will not affect the fair value but will affect future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Notes, but can affect their fair

values. As of December 31, 2023 December 31, 2024, our outstanding principal amount of fixed-rate debt totaled $1.6 $2.7 billion and we had no our floating-rate debt outstanding. As we had no borrowings under our revolving credit facility during 2023, we had no exposure to variable interest rates during the year ended December 31, 2023. Please refer

outstanding totaled $68.5 million. Refer to *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for additional discussion on the fair values of our Senior Notes.

The Federal Reserve increased short-term interest rates during 2023 and 2022. These increases, and any future increases, are likely to increase the cost of and affect our ability to borrow funds.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly affect our revenue, profitability, access to capital, ability to return capital to our stockholders, and future rate of growth. Oil, gas, and NGL prices are subject to unpredictable fluctuations resulting from a variety of factors that are typically beyond our control, including changes in supply and demand associated with the broader macroeconomic environment, constraints on gathering systems, processing facilities, pipelines, rail systems, and other transportation systems, and weather-related events. The markets for oil, gas, and NGLs have been volatile, especially over the last decade, and remain subject to high levels of uncertainty and volatility related to production output from OPEC+, fluctuations in oil and gas demand from China, global shipping channel constraints and disruptions, instability in the Middle East, economic War and Geopolitical Instability, tariffs or trade sanctions associated with the wars between Russia and Ukraine and Israel and Hamas, restrictions, and the potential impacts of these issues on global commodity and financial markets. These circumstances have contributed to inflation, instances of supply chain disruptions, and a rise fluctuations in interest rates, and could have further industry-specific impacts that may require us to adjust our business plan. The realized prices we receive for our production also depend on numerous factors that are typically beyond our control. Refer to *Risk Factors - Risks Related to Commodity Prices and Global Macroeconomics* in Part I, Item 1A of this report. Based on our 2023 2024 production, a 10 percent decrease in our average realized prices for oil, gas, and NGLs would have reduced our oil, gas, and NGL production revenues by approximately $181.4 $218.7 million, $32.8 $24.9 million, and $22.2 $23.5 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the year ended December 31, 2023 December 31, 2024, would have offset the declines in oil, gas, and NGL production revenue by approximately $61.2 $50.3 million.

We enter into commodity derivative contracts in order to reduce the risk of fluctuations in commodity prices. The fair value of our commodity derivative contracts is largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2023 December 31, 2024, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net derivative positions for these products by approximately $30.0 $51.9 million, $5.2 $23.4 million, and $0.7 $1.7 million, respectively.

Off-Balance Sheet Arrangements

We have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPE" or "SPEs"). Please refer Refer to *Off-Balance Sheet Arrangements* within *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report for additional discussion.

Critical Accounting Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with GAAP requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities as of the date of our consolidated financial statements. We base our assumptions and estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate as a result of changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report. We have outlined below, those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Successful Efforts Method of Accounting. GAAP provides two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method, and both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report.

Oil and Gas Reserve Quantities. Our estimated proved reserve quantities and future net cash flows are critical to understanding the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our consolidated financial statements, including the calculations of DD&A expense, impairment of proved and unproved oil and gas properties, and asset retirement obligations. Please refer obligations, and purchase price allocations. Refer to *Oil and Gas Producing Activities* in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report for additional discussion on our accounting policies impacted by estimated reserve quantities.

Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure of discounted future net cash flows calculation requires that a 10 percent discount rate be applied. Although reserve estimates are inherently imprecise and estimates of new discoveries and undeveloped

locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We engage Ryder Scott, an independent reservoir evaluation consulting firm, to audit a minimum of 80 percent of our total calculated proved reserve PV-10. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year end. It should not be assumed that the standardized measure of discounted future net cash flows (GAAP) or PV-10 (non-GAAP) as of December 31, 2023 December 31, 2024, is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based these measures on the unweighted arithmetic average of the first-day-of-the-month price of each month within the trailing 12-month period ended December 31, 2023 December 31, 2024. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimates. Please refer Refer to *Risk Factors* in Part I, Item 1A of this report for additional discussion.

If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, which would reduce future net income. Changes in DD&A rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2023	**2022**	**2021**
	2024	**2023**	**2022**
		MMBOE Change	
		MMBOE Change	
		MMBOE Change	
Revisions resulting from performance (1)			
Removal of net proved undeveloped reserves no longer in our five-year development plan			
Revisions resulting from price changes			
Total			

Note: Amounts may not calculate due to rounding.

(1) For the year ended December 31, 2023, performance revisions consisted of positive revisions of 65.3 MMBOE resulting from changes to decline curve estimates based on reservoir engineering analysis and negative revisions of 28.0 MMBOE related to well performance.

As previously noted, commodity prices are volatile and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes.

We cannot reasonably predict future commodity prices, although we believe that together, the analyses below analyses provide reasonable information regarding the impact of changes in pricing and trends on total estimated net proved reserves. The following table reflects the estimated MMBOE change and percentage change to our total reported estimated net proved reserve volumes from the described hypothetical changes:

		For the year ended December 31, 2023					For the year ended December 31, 2024		
		MMBOE Change	MMBOE Change			Percentage Change		MMBOE Change	Percentage Change
10 percent decrease in SEC pricing (1)	10 percent decrease in SEC pricing (1)	(14.3)	(2)	(2)%	10 percent decrease in SEC pricing (1)	(19.3)	(3)	(3)%	
Average NYMEX strip pricing as of fiscal year end (2)	Average NYMEX strip pricing as of fiscal year end (2)	2.5	—	— %	Average NYMEX strip pricing as of fiscal year end (2)	11.5	2	2 %	
10 percent decrease in net proved undeveloped reserves (3)	10 percent decrease in net proved undeveloped reserves (3)	(26.4)	(4)	(4)%	10 percent decrease in net proved undeveloped reserves (3)	(27.4)	(4)	(4)%	

(1) The change solely reflects the impact of a 10 percent decrease in SEC pricing to the total reported estimated net proved reserve volumes as of December 31, 2023 December 31, 2024, and does not include additional impacts to our estimated net proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs.

(2) The change solely reflects the impact of replacing SEC pricing with the five-year average NYMEX strip pricing as of December 31, 2023 December 31, 2024, and does not include additional impacts to our estimated net proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs. As of December 31, 2023 December 31, 2024, SEC pricing was $78.22 $75.48 per Bbl for oil, $2.64 $2.13 per MMBtu for gas, and $27.72 $28.29 per Bbl for NGLs, and five-year average NYMEX strip pricing was $66.11 $65.69 per Bbl for oil, $3.53 $3.72 per MMBtu for gas, and $25.19 $26.08 per Bbl for NGLs.

(3) The change solely reflects a 10 percent decrease in net proved undeveloped reserves as of December 31, 2023 December 31, 2024, and does not include any additional impacts to our estimated net proved reserves.

Additional reserve information can be found in *Reserves* in Part I, Items 1 and 2 of this report, and in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Impairment of Oil and Gas Proved Properties. Proved oil and gas properties are evaluated for impairment on a depletion pool-by-pool basis and reduced to fair value when events or changes in circumstances indicate that their carrying amount may not be recoverable. We estimate the expected future cash flows of our proved oil and gas properties and compare these undiscounted cash flows to the carrying amount to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the proved oil and gas properties to fair value (or discounted future cash flows). Management estimates future cash flows from all proved reserves and risk adjusted probable and possible reserves using various factors, which are subject to our judgment and expertise, and include, but are not limited to, commodity price forecasts, estimated future operating and capital costs, development plans, and discount rates to incorporate the risk and current market conditions associated with realizing the expected cash flows.

Unproved oil and gas properties are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by asset group and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and our intent to renew leases. We estimate the fair value of unproved properties using a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by us or other market participants.

We cannot predict when or if future impairment charges will be recorded because of the uncertainty in the factors discussed above. Despite any amount of future impairment being difficult to predict, based on our commodity price assumptions as of February 8, 2024 January 31, 2025, we do not expect any material proved oil and gas property impairments in the first quarter of 2024 2025 resulting from commodity price impacts.

Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 8 – Fair Value Measurements* in Part II, Item 8 of this report for discussion of impairments of oil and gas properties recorded for the years ended December 31, 2022, and 2021.

Revenue Recognition. We predominately derive our revenue from the sale of produced oil, gas, and NGLs. Our revenue recognition policy is a critical accounting estimate because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. A 10 percent change in our revenue accrual at year-end 2023 would have affected total operating revenues by approximately $17.5 million for the year ended December 31, 2023. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 2 – Revenue from Contracts with Customers* in Part II, Item 8 of this report for additional discussion.

Derivative Financial Instruments. We periodically enter into commodity derivative contracts to mitigate a portion of our exposure to oil, gas, and NGL price volatility and location differentials. We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income (loss). The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Income Taxes. We account for deferred income taxes, whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the consolidated financial statements and the tax basis of assets and liabilities, as measured using currently enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. We record deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period, as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement as well as significant enacted tax rate changes could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by approximately $9.1 million for the year ended December 31, 2023. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 4 – Income Taxes* in Part II, Item 8 of this report for additional discussion.

Accounting Matters

Please refer Refer to *Recently Issued Accounting Standards Guidance* in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report for information on new authoritative accounting guidance.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes, and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. For additional information about hydraulic fracturing and related environmental matters, please refer to *Risk Factors – Risks Related to Oil and Gas Operations and the Industry Government Regulations – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.*

Climate Change and Air Quality. In June 2013, President Obama announced a Climate Action Plan designed to further reduce GHG emissions and prepare the nation for the physical effects that may occur as a result of climate change. The Climate Action Plan targeted methane reductions from the oil and gas sector as part of a comprehensive interagency methane strategy. As part of the Climate Action Plan, on May 12, 2016, the EPA issued final regulations applicable to new, modified, or reconstructed sources that amended and expanded 2012 regulations for the oil and gas sector by, among other things, setting emission limits for volatile organic compounds ("VOCs" or "VOC") and methane, a GHG, and added requirements for previously unregulated sources. The 2016 NSPS requires reduction of methane and VOCs from certain activities in oil and gas production, processing, transmission and storage and applies to facilities constructed, modified, or reconstructed after September 18, 2015. The regulation requires, among other things, GHG and VOC emission limits for certain equipment, such as centrifugal compressors and reciprocating compressors; semi-annual leak detection and repair for well sites and quarterly for boosting and garnering compressor stations and gas transmission compressor stations; control requirements and emission limits for pneumatic pumps; and additional requirements for control of GHGs and VOCs from well completions. On September 14, and 15, 2020, the EPA finalized amendments to the 2012 and 2016 NSPS that removed transmission and storage infrastructure from regulation of methane emissions and other VOCs, as well as removed methane control requirements. The portion of the 2020 amendments that removed the transmission and storage infrastructure from the regulations was disapproved by the Congressional Review Act in 2021. In November 2021, the EPA proposed to expand the requirements of the 2012 and 2016 NSPS and also include requirements for states to develop performance standards to control methane emissions from existing sources. In December 2022, the EPA issued a supplemental proposal to update, strengthen, and expand the 2021 proposed rules. The EPA finalized the rule in December 2023. In March 2024, the EPA announced a final rule that implements a waste emissions charge and new reporting requirements for facilities and wells completed after May 7, 2024.

States are also required to comply with the NAAQS. The oil and gas sector is often subjected to additional controls when areas within states are not attaining the ozone NAAQS as the VOCs emitted by the oil and gas sector are a precursor to ozone formation. The ozone NAAQS was set at 70 parts per billion ("ppb") in 2015. In 2023, the EPA announced its plan to perform a full and complete review of the ozone NAAQS and intends to release an integrated review plan in 2024. NAAQS. The results of this review could result in changes to the ozone NAAQS which, if lowered, may result in additional actions by states requiring further emission controls and associated costs. Oil and gas facilities operating in areas that are determined to be out of compliance with the 70 ppb requirement or a lowered ozone NAAQS may be subject to increased emission controls and associated costs of compliance. As part of the integrated review process, the EPA held a workshop in May 2024 to discuss policy-relevant science that will inform the EPA's current review of the air quality criteria and the NAAQS for ozone and related photochemical oxidants.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and many of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, there have been international conventions and efforts to establish standards for the reduction of GHGs globally, including the Paris accords Agreement in December 2015. The conditions for entry into force of the Paris accords Agreement were met on October 5, 2016, and the Agreement went into force 30 days later on November 4, 2016. In January of 2025, President Trump issued an executive order that initiated the process for the United States to exit the Paris Agreement. At the United Nations Climate Change Conference in Glasgow in 2021, the United States and the European Union announced the Global Methane Pledge that aims to reduce methane emissions by 30 percent compared with 2020 levels.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Judicial challenges to new regulatory measures are likely and we cannot predict the outcome of such challenges. New regulatory suspensions, revisions, or rescissions and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. Finally, scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere produce climate changes that likely have significant physical effects, such as increased frequency and severity of storms, droughts, floods, and other climatic events. Such effects could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of GHG emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration, and low carbon fuel standards, could benefit us in a variety of ways. For example, although federal regulation and climate change legislation could reduce the overall demand for the oil and gas that we produce, the relative demand for gas may increase because the burning of gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources such as wind or solar power become more prevalent, gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, gas may become a more attractive transportation fuel. For each of the years ended December 31, 2023 December 31, 2024, and 2022, 2023, approximately 37 percent and 40 percent, respectively, of our production on a per BOE basis was gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and gas reservoirs, could also benefit us through the potential to obtain GHG emission allowances or offsets from or government incentives for the sequestration of carbon dioxide. For additional information about climate change, air quality, and related environmental matters, refer to *Risk Factors – Risks Related to Government Regulations – Legislative and regulatory initiatives and litigation related to global warming and climate change* *could have an adverse effect on our operations and the demand for oil, gas, and NGLs, and could result in significant litigation, capital, and related expenses* and *Federal and state regulatory initiatives relating to air quality and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays.*

Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion amortization expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we believe provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement as further described in *Note 5 – Long-Term Debt* in Part II, Item 8 of this report. Agreement. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our revolving credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX, we would be in default, an event that would prevent us from borrowing under our revolving credit facility and would therefore materially limit a significant source of our liquidity. In addition, if we are in default under our revolving credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing each series of our outstanding Senior Notes as defined in would be entitled to exercise all of their remedies for default. Refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report, would be entitled to exercise all for definition of their remedies for default. and further detail about our Credit Agreement.

The following table provides reconciliations of our net income (GAAP) and net cash provided by operating activities (GAAP) to adjusted EBITDAX (non-GAAP) for the periods presented:

	For the Years Ended December 31,		
	2023	**2022**	**2021**
	2024	**2023**	**2022**
	(in thousands)		
	(in thousands)		
	(in thousands)		
Net income (GAAP)			
Interest expense			
Interest income			
Income tax expense			
Depletion, depreciation, amortization, and asset retirement obligation liability accretion			
Depletion, depreciation, and amortization			
Exploration (1)			
Impairment			
Stock-based compensation expense			
Stock-based compensation expense			
Stock-based compensation expense			
Net derivative (gain) loss			
Net derivative settlement gain (loss)			
Loss on extinguishment of debt			
Loss on extinguishment of debt			
Loss on extinguishment of debt			
Other, net			
Adjusted EBITDAX (non-GAAP)			
Interest expense			
Interest income			
Income tax expense			
Exploration (1) (2)			
Amortization of debt discount and deferred financing costs			
Deferred income taxes			
Other, net			
Net change in working capital			
Net cash provided by operating activities (GAAP)			

(1) Stock-based compensation expense is a component of the exploration expense and general and administrative expense line items on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration expense.

(2) For the year ended December 31, 2024, amount excludes certain capital expenditures related to one well deemed non-commercial. For the year ended December 31, 2023, amount excludes certain capital expenditures related to unsuccessful exploration activity for one well that experienced technical issues during the drilling phase. For the year ended December 31, 2022, amount excludes certain capital expenditures related to unsuccessful exploration efforts outside of our core areas of operation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this Item is provided under the captions *Interest Rate Risk* and *Commodity Price Risk* in Item 7 above, as well as under the section entitled *Summary of Oil, Gas, and NGL Derivative Contracts in Place* in *Note 7 – Derivative Financial Instruments* in Part II, Item 8 of this report and is incorporated herein by reference.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company and subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries (the Company) as of December 31, 2023 December 31, 2024 and 2022, 2023, the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2023 December 31, 2024, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023 December 31, 2024 and 2022, 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 December 31, 2024, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023 December 31, 2024, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 22, 2024 February 20, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or is required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depletion, Depreciation and Amortization ("DD&A") of Proved Oil and Gas Properties

Description of the Matter	At December 31, 2023 December 31, 2024, the net book value of the Company's proved oil and gas properties was $4.6 billion $6.7 billion, and depletion, depreciation and amortization and asset retirement obligation liability accretion was $690.5 million $809.3 million for the year then ended. As described in Note 1 under to the consolidated financial statements, the Company follows the successful efforts method of accounting of its oil and gas properties. Under the successful efforts method of accounting, the capitalized costs of proved properties are depleted using the units-of-production method based on proved oil and gas reserves, as estimated by the Company's engineers. Proved oil and gas reserve estimates are impacted by various inputs, including historical production, oil and gas price assumptions, and future operating and capital cost assumptions, among others, and requires the expertise of the Company's engineers in evaluating and interpreting the relevant data. Because of the complexity involved in estimating oil and gas reserves, management used independent petroleum engineers to audit the estimates prepared by the Company's engineers as of December 31, 2023 December 31, 2024. Auditing the Company's impact of proved oil and gas reserves on DD&A calculation is especially complex because of the use of the work of the Company's engineers and the independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated Addressing the design matter involved performing procedures and tested evaluating audit evidence in connection with forming our overall opinion on the operating consolidated financial statements. These procedures included testing the effectiveness of the Company's controls that address the risk of material misstatement relating to management's estimates of proved oil and natural gas reserves as an input reserve volumes. The work of management's specialists was used in performing the procedures to evaluate the DD&A expense calculations, including management's controls over reasonableness of the proved oil and natural gas reserve volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included i) evaluating the methods and assumptions used by the specialists, ii) testing the completeness and accuracy of the financial data used in estimating proved oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's engineers responsible for the preparation of the reserve estimates and the independent petroleum engineers used to audit the estimates. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data used by the engineers, in estimating proved oil specialists related to historical production volumes, iii) evaluating the specialists' findings related to estimated future production volumes by comparing the estimate to relevant historical and gas reserves by agreeing significant inputs to source documentation, where available, on a sample basis, and we assessed the inputs for reasonableness based on our review of corroborative evidence and consideration of any contrary evidence. We also tested that the DD&A expense calculations, are based on appropriate proved oil and gas reserves amounts from the Company's reserve report. current period information, as applicable.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2012.

Denver, Colorado

February 22, 2024 20, 2025

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31,	
	2023	**2022**
	2024	**2023**
ASSETS		
Current assets:		
Current assets:		
Current assets:		
Cash and cash equivalents		
Cash and cash equivalents		
Cash and cash equivalents		
Accounts receivable		
Derivative assets		
Prepaid expenses and other		
Total current assets		
Property and equipment (successful efforts method):		
Property and equipment (successful efforts method):		
Property and equipment (successful efforts method):		
Proved oil and gas properties		
Proved oil and gas properties		

Proved oil and gas properties
Accumulated depletion, depreciation, and amortization
Unproved oil and gas properties, net of valuation allowance of $35,362 and $38,008, respectively
Unproved oil and gas properties, net of valuation allowance of $32,680 and $35,362, respectively
Wells in progress
Other property and equipment, net of accumulated depreciation of $59,669 and $56,512, respectively
Other property and equipment, net of accumulated depreciation of $59,669 and $56,512, respectively
Other property and equipment, net of accumulated depreciation of $59,669 and $56,512, respectively
Other property and equipment, net of accumulated depreciation of $61,737 and $59,669, respectively
Other property and equipment, net of accumulated depreciation of $61,737 and $59,669, respectively
Other property and equipment, net of accumulated depreciation of $61,737 and $59,669, respectively
Total property and equipment, net
Noncurrent assets:
Noncurrent assets:
Noncurrent assets:
Noncurrent assets:
Derivative assets
Derivative assets
Derivative assets
Other noncurrent assets
Total noncurrent assets
Total assets
LIABILITIES AND STOCKHOLDERS’ EQUITY
LIABILITIES AND STOCKHOLDERS’ EQUITY
LIABILITIES AND STOCKHOLDERS’ EQUITY
Current liabilities:
Current liabilities:
Current liabilities:
Accounts payable and accrued expenses
Accounts payable and accrued expenses
Accounts payable and accrued expenses
Derivative liabilities
Other current liabilities
Total current liabilities
Noncurrent liabilities:
Noncurrent liabilities:
Noncurrent liabilities:
Revolving credit facility
Revolving credit facility
Revolving credit facility
Senior Notes, net
Asset retirement obligations
Asset retirement obligations
Asset retirement obligations
Net deferred tax liabilities
Net deferred tax liabilities
Net deferred tax liabilities
Derivative liabilities
Other noncurrent liabilities
Total noncurrent liabilities
Commitments and contingencies (note 6)
Commitments and contingencies (note 6)
Commitments and contingencies (note 6)

Stockholders' equity:	
Stockholders' equity:	
Stockholders' equity:	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 115,745,393 and 121,931,676 shares, respectively	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 115,745,393 and 121,931,676 shares, respectively	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 115,745,393 and 121,931,676 shares, respectively	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 114,461,934 and 115,745,393 shares, respectively	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 114,461,934 and 115,745,393 shares, respectively	
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 114,461,934 and 115,745,393 shares, respectively	
Additional paid-in capital	
Retained earnings	
Accumulated other comprehensive loss	
Total stockholders' equity	
Total liabilities and stockholders' equity	

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	For the Years Ended December 31,		For the Years Ended December 31,	For the Years Ended December 31,
	2023	2022	2021	
	2024	2023	2022	
Operating revenues and other income:				
Oil, gas, and NGL production revenue				
Oil, gas, and NGL production revenue				
Oil, gas, and NGL production revenue				
Other operating income				
Other operating income				
Other operating income				
Other operating income, net				
Other operating income, net				
Other operating income, net				
Total operating revenues and other income				
Operating expenses:				
Operating expenses:				
Operating expenses:				
Oil, gas, and NGL production expense				
Oil, gas, and NGL production expense				
Oil, gas, and NGL production expense				
Depletion, depreciation, amortization, and asset retirement obligation liability accretion				
Depletion, depreciation, and amortization				
Exploration				
Impairment				
Impairment				
General and administrative				
Impairment				
General and administrative				
General and administrative				
Net derivative (gain) loss				
Other operating expense, net				
Total operating expenses				

Income from operations	
Income from operations	
Income from operations	
Interest expense	
Interest expense	
Interest expense	
Interest income	
Loss on extinguishment of debt	
Other non-operating expense	
Income from before income taxes	
Income from before income taxes	
Income from before income taxes	
Income tax expense	
Net income	
Basic weighted-average common shares outstanding	
Basic weighted-average common shares outstanding	
Basic weighted-average common shares outstanding	
Diluted weighted-average common shares outstanding	
Basic net income per common share	
Diluted net income per common share	

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	For the Years Ended December 31,		For the Years Ended December 31,	For the Years Ended December 31,
	2023	**2022**	**2021**	
	2024	**2023**	**2022**	
Net income				
Other comprehensive income, net of tax:				
Pension liability adjustment (1)				
Pension liability adjustment (1)				
Pension liability adjustment (1)				
Total other comprehensive income, net of tax				
Total comprehensive income				

(1) Please refer Refer to *Note 11 12 – Pension Benefits* for additional discussion of the pension liability adjustment.

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except share data and dividends per share)

	Common Stock Shares	Additional Paid-in Capital	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares							
	Shares							
Balances, January 1, 2021								
Balances, January 1, 2021								
Balances, January 1, 2021								

Balances, January 1, 2022
Balances, January 1, 2022
Balances, January 1, 2022
Net income
Other comprehensive income
Net cash dividends declared, $0.02 per share
Net cash dividends declared, $0.31 per share
Issuance of common stock under Employee Stock Purchase Plan
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings
Stock-based compensation expense
Stock-based compensation expense
Stock-based compensation expense
Issuance of common stock through cashless exercise of Warrants
Issuance of common stock through cashless exercise of Warrants
Issuance of common stock through cashless exercise of Warrants
Balances, December 31, 2021
Balances, December 31, 2021
Balances, December 31, 2021
Net income
Other comprehensive income
Net cash dividends declared, $0.31 per share
Issuance of common stock under Employee Stock Purchase Plan
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings
Stock-based compensation expense
Purchase of shares under Stock Repurchase Program
Purchase of shares under Stock Repurchase Program
Purchase of shares under Stock Repurchase Program
Balances, December 31, 2022
Net income
Other comprehensive income
Net cash dividends declared, $0.63 per share
Issuance of common stock under Employee Stock Purchase Plan
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings
Stock-based compensation expense
Issuance of common stock through cashless exercise of Warrants
Purchase of shares under Stock Repurchase Program
Other
Balances, December 31, 2023
Net income
Other comprehensive income
Net cash dividends declared, $0.76 per share
Issuance of common stock under Employee Stock Purchase Plan

Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings
Stock-based compensation expense
Purchase of shares under Stock Repurchase Program
Purchase of shares under Stock Repurchase Program
Purchase of shares under Stock Repurchase Program
Balances, December 31, 2024

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31,		For the Years Ended December 31,	For the Years Ended December 31,
	2023	2022	2021	
	2024	2023	2022	
Cash flows from operating activities:				
Net income				
Net income				
Net income				
Adjustments to reconcile net income to net cash provided by operating activities:				
Depletion, depreciation, amortization, and asset retirement obligation liability accretion				
Depletion, depreciation, and amortization				
Depletion, depreciation, amortization, and asset retirement obligation liability accretion				
Depletion, depreciation, and amortization				
Depletion, depreciation, amortization, and asset retirement obligation liability accretion				
Impairment				
Depletion, depreciation, and amortization				
Stock-based compensation expense				
Stock-based compensation expense				
Stock-based compensation expense				
Net derivative (gain) loss				
Net derivative settlement gain (loss)				
Amortization of debt discount and deferred financing costs				
Loss on extinguishment of debt				
Deferred income taxes				
Other, net				
Changes in working capital:				
Accounts receivable				
Accounts receivable				
Accounts receivable				
Prepaid expenses and other				
Accounts payable and accrued expenses				
Net cash provided by operating activities				
Cash flows from investing activities:				
Cash flows from investing activities:				
Cash flows from investing activities:				
Capital expenditures				
Capital expenditures				
Capital expenditures				
Acquisition of proved and unproved oil and gas properties				
Other, net				

Net cash used in investing activities
Cash flows from financing activities:
Cash flows from financing activities:
Cash flows from financing activities:
Proceeds from revolving credit facility
Proceeds from revolving credit facility
Proceeds from revolving credit facility
Repayment of revolving credit facility
Debt issuance costs related to revolving credit facility
Net proceeds from Senior Notes
Cash paid to repurchase Senior Notes
Repurchase of common stock
Dividends paid
Net proceeds from sale of common stock
Dividends paid
Net share settlement from issuance of stock awards
Other, net
Net cash used in financing activities
Net cash provided by (used in) financing activities
Net cash provided by (used in) financing activities
Net cash provided by (used in) financing activities
Net change in cash, cash equivalents, and restricted cash
Net change in cash, cash equivalents, and restricted cash
Net change in cash, cash equivalents, and restricted cash
Cash, cash equivalents, and restricted cash at beginning of period
Cash, cash equivalents, and restricted cash at end of period
Supplemental schedule of additional cash flow information and non-cash activities:
Supplemental schedule of additional cash flow information and non-cash activities:
Supplemental schedule of additional cash flow information and non-cash activities:
Operating activities:
Operating activities:
Operating activities:
Cash paid for interest, net of capitalized interest
Cash paid for interest, net of capitalized interest
Cash paid for interest, net of capitalized interest
Net cash paid for income taxes
Investing activities:
Changes in capital expenditure accruals
Changes in capital expenditure accruals
Changes in capital expenditure accruals
Non-cash financing activities (1)

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(in thousands)

		For the Years Ended December 31,	
	2024	2023	2022
Supplemental schedule of additional cash flow information and non-cash activities:			
Operating activities:			
Cash paid for interest, net of capitalized interest (1)	$ (88,389)	$ (86,947)	$ (134,240)
Net cash paid for income taxes	$ (26,904)	$ (8,975)	$ (10,576)
Investing activities:			
Changes in capital expenditure accruals	$ (24,342)	$ 80,794	$ 29,789
Non-cash financing activities (2)			

(1) Please refer Cash paid for interest, net of capitalized interest during the year ended December 31, 2024, does not include $9.0 million in fees paid to secure firm commitments for senior unsecured bridge term loans in connection with the Uinta Basin Acquisition, as defined in *Note 17 – Acquisitions.*

(2) Refer to *Note 5 – Long-Term Debt* for discussion of the debt transactions completed during the years ended December 31, 2022 December 31, 2024, and 2021. 2022.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies

Description of Operations

SM Energy Company, together with its consolidated subsidiaries, is an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas. Texas and Utah.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X. Intercompany accounts and transactions have been eliminated. In connection with the preparation of the accompanying consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of December 31, 2023, through the filing of this report. Additionally, certain prior period amounts have been reclassified to conform to current period presentation in the accompanying consolidated financial statements.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities as of the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of DD&A expense, impairment of proved and unproved oil and gas properties, acquisitions of oil and gas properties, and asset retirement obligations, each of which represents a significant component of the accompanying consolidated financial statements.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Accounts Receivable

The Company's accounts receivable primarily consist of receivables due from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company's oil, gas, and NGL receivables are collected within 30 to 90 days and the Company has had minimal bad debts. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. Please refer Refer to *Note 13 14 – Accounts Receivable and Accounts Payable and Accrued Expenses* for additional disclosure.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related energy-related industries. The creditworthiness of customers and other counterparties is regularly reviewed.

The Company does not believe the loss of any single purchaser of its production would materially affect its operating results, as oil, gas, and NGLs are products with well-established markets and numerous purchasers in the Company's operating areas.

The following major customers and entities under common control accounted for 10 percent or more of the Company's total oil, gas, and NGL production revenue for at least one of the periods presented:

		For the Years Ended December 31,			For the Years Ended December 31,			For the Years Ended December 31,						
		2023	2022	2021										
		2024			2023			2022						
		Amount Amount Amount	% of total		Amount		% of total	Amount	% of total					
					(in thousands) (in thousands) (in thousands)									
Major customer #1	Major customer #1	24 %	24 %	27 %	Major customer #1	$899,609	34	34 %	$580,557	24	24 %	$848,595	24	24 %
Major customer #2	Major customer #2	11 %	7 %	9 %	Major customer #2	$248,383	9	9 %	$260,574	11	11 %	$255,395	7	7 %
Major customer #3		6 %	8 %	15 %										
Group #1 of entities under common control		22 %	24 %	18 %										
Group of entities under common control Group of entities under common control Group of entities under common control		$426,248	16 %		$530,131		22 %	$830,276	24 %					

For its commodity derivative instruments, the Company's policy is to only enter into contracts with affiliates of the lenders under its Credit Agreement as its derivative counterparties, and each counterparty must have certain minimum investment grade senior unsecured debt ratings.

The Company maintains its primary bank accounts with a large, multinational bank that has branch locations in the Company's areas of operation. The Company's policy is to diversify its concentration of cash and cash equivalent investments among multiple institutions and investment products to limit the amount of credit exposure to any single institution or investment.

Oil and Gas Producing Activities

Proved properties. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method, property acquisition costs and development costs are capitalized when incurred. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities in the field, are depleted on an asset group a pool-by-pool basis (properties aggregated based on geographical and geological characteristics) using the units-of-production method based on estimated net proved developed oil and gas reserves. Similarly, proved leasehold costs are depleted on the same asset group pool-by-pool basis; however, the units-of-production method is based on estimated total net proved oil and gas reserves. The computation of DD&A expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment.

Proved oil and gas property costs are evaluated for impairment on a depletion pool-by-pool basis and reduced to fair value when there is an indication that associated carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future cash flows to a single present value amount, to measure the fair value of proved properties using a discount rate, price and cost forecasts, and certain reserve risk-adjustment factors, as selected by the Company's management. The Company uses a discount rate that represents a current market-based weighted average cost of capital. The discount rate typically ranges from 10 percent to 15 percent. The prices for oil and gas are forecast based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecast using OPIS Mont Belvieu pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Certain undeveloped reserve estimates are also risk-adjusted given the risk to related projected cash flows due to performance and exploitation uncertainties.

The partial sale of a proved property within an existing field asset group is accounted for as a normal retirement and no gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

Unproved properties. The unproved oil and gas properties line item on the accompanying consolidated balance sheets ("accompanying balance sheets") consists of the costs incurred to acquire unproved leases. Leasehold costs allocated to those leases, or partial leases that have associated proved reserves recorded, are reclassified to proved properties and depleted on an asset group basis using the units-of-production method based on estimated total proved oil and gas reserves. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by asset group and the portion of such costs estimated to be nonproductive prior to lease expiration are recognized as a valuation allowance and amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and the Company's intent to renew leases. To measure the fair value of unproved properties, the Company uses a market an income approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk-weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants.

For the sale of unproved properties where the original cost has been partially or fully amortized by providing a valuation allowance on an asset group basis, neither a gain nor loss is recognized unless the sales price exceeds the original cost of the property, in which case a gain shall be recognized in the accompanying statements of operations in the amount of such excess.

Exploratory. Exploratory geological and geophysical, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Under the successful efforts method of accounting for oil and gas properties, exploratory well costs are initially capitalized pending the determination of whether proved reserves have been discovered. If proved reserves are discovered, exploratory well costs will be capitalized as proved properties and will be accounted for following the successful efforts method of accounting described above. If proved reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in the cash flows from investing activities section as part of capital expenditures within the accompanying statements of cash flows.

Please refer Refer to *Note 8 – Fair Value Measurements* for additional information.

Other Property and Equipment

Other property and equipment such as facilities, equipment inventory, office furniture and equipment, buildings, and computer hardware and software, are recorded at cost. The Company capitalizes certain software costs incurred during the application development stage. The application development stage generally includes software design, configuration, testing, and installation activities. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using either the straight-line method over the estimated useful lives of the assets, which range from three to 30 years, or the unit of output method when appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the Company's accounts.

Facilities and equipment inventory costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. To measure the fair value of facilities and equipment inventory, the Company uses an income valuation technique or market approach depending on the quality of information available to support management's assumptions and the circumstances. For facilities, the valuation includes consideration of the proved and unproved assets supported by the facilities, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties, including facilities requiring decommissioning. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired, or a facility is constructed. The increase in carrying value is included in the proved oil and gas properties line item in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective long-lived assets. Asset retirement obligation liability accretion expense is included in the depletion, depreciation, and amortization line on the accompanying statements of operations. Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's plugging and abandonment liabilities range from 5.5 percent to 12 percent. In periods subsequent to initial measurement of the liability, the Company must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or economic life, changes in inflation factors, or the Company's credit-adjusted risk-free rate as market conditions warrant. Please refer Refer to *Note 14 15 – Asset Retirement Obligations* for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2023 December 31, 2024, and 2022. 2023.

Derivative Financial Instruments

The Company periodically regularly enters into commodity derivative instruments contracts to mitigate a portion of its exposure to oil, gas, and NGL price volatility and location differentials for its expected future oil, gas, and NGL production, and the associated effect on cash flows. These instruments typically include All commodity derivative contracts that the Company enters into are for other-than-trading purposes. The Company's commodity derivative contracts generally consist of price swaps swap, collar, and collar arrangements, as well as, basis swaps and roll differential swaps. swap arrangements. Commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The fair value of the Company's commodity derivative contracts is measured based on, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The Company does not designate its commodity derivative contracts as hedging instruments. Accordingly, the Company reflects gains

and losses from changes in the fair value of its commodity derivative instruments contracts in its the accompanying statements of operations as they occur. such changes occur, rather than deferring any such amounts in accumulated other comprehensive income (loss). Gains and losses on net derivative settlements are included within the cash flows from operating activities section of the accompanying statements of cash flows. Please refer Refer to *Note 7 – Derivative Financial Instruments* for additional discussion.

Revenue Recognition

The Company derives revenue predominately from the sale of produced oil, gas, and NGLs. Revenue is recognized at the point in time when custody and title ("control") of the product transfers to the purchaser, which may differ depending on the applicable contractual terms. Revenue accruals are recorded monthly and are based on estimated production delivered to a purchaser and the expected price to be received. The Company uses knowledge of its properties, contractual arrangements, historical performance, NYMEX, local spot market, and OPIS prices, and other factors as the basis of these estimates. Variances between estimates and the actual amounts received are recorded in the month payment is received. Please refer Refer to *Note 2 – Revenue from Contracts with Customers* for additional discussion.

Stock-Based Compensation

At December 31, 2023 December 31, 2024, the Company had stock-based employee compensation plans that included RSUs and Performance Share Units ("PSU or "PSUs") issued to employees, RSUs and restricted stock issued to non-employee directors, and an employee stock purchase plan available to eligible employees. The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance, which is based on the estimated fair value of these awards determined at the time of grant, and is included within the general and administrative and exploration expense line items in the accompanying statements of operations. For stock-based compensation awards containing non-market based performance conditions, the Company evaluates the probability of the number of shares that are expected to vest, and then adjusts the expense to reflect the number of shares expected to vest and the cumulative vesting period met to date. Further, the Company accounts for forfeitures of stock-based compensation awards as they occur. Please refer Refer to *Note 10 – Compensation Plans* for additional discussion.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the accompanying consolidated financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. Judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis. The Company's federal and state income tax returns are not filed before the consolidated financial statements are prepared. Therefore, the Company estimates the tax basis of its assets and liabilities at the end of each period, as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates used and actual amounts reported are recorded in the periods in which the income tax returns are filed. The cumulative effect of enacted tax rate changes on the net balance of reported amounts of assets and liabilities is recognized in the period of enactment. The Company's policy is to record interest related to income taxes in the interest expense line item in the accompanying statements of operations, and to record penalties related to income taxes in the other non-operating expense line item in the accompanying statements of operations. Please refer Refer to *Note 4 – Income Taxes* for additional discussion.

Earnings per Share

The Company uses the treasury stock method to determine the effect of potentially dilutive instruments. Please refer Refer to *Note 9 – Earnings Per Share* for additional discussion.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that, under GAAP, are reported as separate components of stockholders' equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of comprehensive income. The Company's policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach. Please refer Refer to *Note 11 12 – Pension Benefits* for detail on the changes in the balances of components comprising adjustments impacting other comprehensive income.

Fair Value of Financial Instruments

The Company's financial instruments, including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The Company's Senior Notes, as defined in *Note 5 – Long-Term Debt*, are recorded at cost, net of unamortized deferred financing costs, and their respective fair values are disclosed in *Note 8 – Fair Value Measurements.* Additionally, the Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Leases

The Company accounts for leases in accordance with ASC Topic 842, *Leases*, ("Topic 842"), which requires lessees to recognize operating and finance leases with terms greater than 12 months on the balance sheet. The Company evaluates a contractual arrangement at its inception to determine if it is a lease or contains an identifiable lease component. Certain leases may contain both lease and non-lease components. The Company's policy for all asset classes is to combine lease and non-lease components together and account for the arrangement as a single lease.

Certain assumptions and judgments made by the Company when evaluating a contract that meets the definition of a lease under Topic 842 include those to determine the discount rate and lease term. Unless implicitly defined, the Company determines the present value of future lease payments using an estimated incremental borrowing rate based on a yield curve analysis that factors in certain assumptions, including the term of the lease and credit rating of the Company at lease inception. The Company evaluates each contract containing a lease arrangement at inception to determine the length of the lease term when recognizing a right-of-use ("ROU") asset and corresponding lease liability. When determining the lease term, options available to extend or early terminate the arrangement are evaluated and included when it is reasonably certain an option will be exercised. Exercising an early termination option may result in an early termination penalty depending on the terms of the underlying agreement. The Company excludes from the balance sheet leases with terms that are less than one year.

An ROU asset represents a lessee's right to use an underlying asset for the lease term, while the associated lease liability represents the lessee's obligations to make lease payments. At the commencement date, which is the date on which a lessor makes an underlying asset available for use by a lessee, a lease ROU asset and corresponding lease liability is recognized based on the present value of the future lease payments. The initial measurement of lease payments may also be adjusted for certain items, including options that are reasonably certain to be exercised, such as options to purchase the asset at the end of the lease term, or options to extend or early terminate the lease. Excluded from the initial measurement of an ROU asset and corresponding lease liability are certain variable lease payments, such as payments made that vary depending on actual usage or performance.

Subsequent to initial measurement, costs associated with the Company's operating leases are either expensed or capitalized depending on how the underlying ROU asset is utilized and in accordance with GAAP requirements. When calculating the Company's ROU asset and liability for a contractual arrangement that qualifies as an operating lease, the Company considers all of the necessary payments made or that are expected to be made upon commencement of the lease. As discussed above, excluded from the initial measurement are certain variable lease payments, which for the Company's drilling rigs, completion crews, and midstream agreements, may be a significant component of the total lease costs. Please refer Refer to *Note 12 13 – Leases* for additional discussion.

Industry, Segment Geographic, and Geographic Segment Information

The Company operates in the oil and gas extraction industry, focused on exploration and production segment of the oil and gas industry, activities, onshore in the United States. The Company reports as a single industry has one reportable segment. Refer to *Note 11 – Segment Reporting* for additional discussion.

Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or SPEs, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that the Company is the primary beneficiary of a variable interest entity, that entity is consolidated into the Company's consolidated financial statements. The Company has not been involved in any unconsolidated SPE transactions during 2023 2024 or 2022, 2023, or through the filing of this report.

Recently Issued Accounting Standards Guidance

Accounting Standards Updates. In October 2023, November 2024, the FASB issued ASU No. 2023-06, 2024-03, *Disclosure Improvements: Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40):Disaggregation of Income Statement Expenses* ("ASU 2023-06" 2024-03"). ASU 2023-06 2024-03 was issued to modify improve disclosures about a public business entity's expenses and address requests from investors for more detailed information about the disclosure or presentation requirements types of a variety of topics expenses in commonly presented expense captions. ASU 2024-03 is effective for the codification. The effective date for each amendment will be the date on which the SEC's removal of the related disclosure from Regulation S-X or Regulation S-K becomes effective, fiscal years beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption prohibited. permitted. The guidance is to be applied on a prospective basis; however, retrospective application is permitted. The Company evaluated is within the scope of this ASU 2023-06 and does not expect expects to adopt ASU 2024-03 on January 1, 2027, on a prospective basis, and adoption will result in new disclosures as prescribed by the adoption of the applicable amendments to have a material effect on its consolidated financial statements and related disclosures. guidance.

In November 2023, the FASB issued ASU No. 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures (*" ("ASU 2023-07")*)*. ASU 2023-07 was issued to improve the disclosures about a public entity's reportable segments and to provide additional, more detailed information about a reportable segment's expenses. The Company adopted ASU 2023-07 is effective for fiscal years beginning after December 15, 2023 on December 31, 2024, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The guidance is to be applied on a retrospective basis basis. Refer to all prior periods presented in the financial statements. The Company is within the scope of this ASU and is evaluating the impact of this ASU on its consolidated financial statement disclosures.*Note 11 – Segment Reporting* for additional discussion.

In December 2023, the FASB issued ASU No. 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* (("ASU 2023-09"))*.* ASU 2023-09 was issued to improve the disclosures related to rate reconciliations and income taxes paid. ASU 2023-09 is effective for annual periods beginning after December 15, 2024, with early adoption permitted. The guidance should is to be applied on a prospective basis, basis; however, retrospective application is permitted. The Company adopted ASU 2023-09 on January 1, 2025, on a prospective basis, and will present the required new disclosures in the 2025 Form 10-K.

SEC Final Rule to Enhance and Standardize Climate-Related Disclosures. On March 6, 2024, the SEC adopted final rules to require registrants to disclose certain climate-related information in registration statements and annual reports. On April 4, 2024, the SEC issued an order staying the final rules pending completion of judicial review of the petitions challenging the final rules. The order does not amend the compliance dates contemplated by the final rules, which are applicable to the Company for fiscal years beginning with the Company's annual report on Form 10-K for the fiscal year ended December 31, 2025. The Company is within the scope of this ASU and is currently evaluating the potential impact of this ASU the final rules on its consolidated financial statement statements and related disclosures.

As of the filing of this report, the Company has not elected to early adopt ASU 2023-07 or ASU 2023-09.

As of December 31, 2023 December 31, 2024, and through the filing of this report, no other ASUs have accounting guidance has been issued and not yet adopted that are applicable to the Company and that would have a material effect on the Company's consolidated financial statements and related disclosures.

Note 2 – Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs from its Midland Basin, and South Texas, and Uinta Basin assets. Oil, gas, and NGL production revenue presented within the accompanying statements of operations reflects revenue generated from contracts with customers.

The tables below present oil, gas, and NGL production revenue by product type for each of the Company's operating areas for the years ended December 31, 2023, 2022, and 2021: areas:

	For the year ended December 31, 2024			
	Midland Basin	**South Texas**	**Uinta Basin**	**Total**
	(in thousands)			
Oil production revenue	$ 1,447,679	$ 542,704	$ 197,098	$ 2,187,481
Gas production revenue	118,455	123,685	6,932	249,072
NGL production revenue	634	234,098	—	234,732
Total	$ 1,566,768	$ 900,487	$ 204,030	$ 2,671,285
Relative percentage	59 %	34 %	7 %	100 %

	For the year ended December 31, 2023		
	Midland Basin	**South Texas**	**Total**
	(in thousands)		

Oil production revenue	$ 1,347,780	$ 465,995	$ 1,813,775
Gas production revenue	175,183	152,700	327,883
NGL production revenue	687	221,544	222,231
Total	$ 1,523,650	$ 840,239	$ 2,363,889
Relative percentage	64 %	36 %	100 %

	For the year ended December 31, 2022		
	Midland Basin	South Texas	Total
	(in thousands)		
Oil production revenue	$ 1,816,597	$ 453,471	$ 2,270,068
Gas production revenue	432,831	358,049	790,880
NGL production revenue	986	283,972	284,958
Total	$ 2,250,414	$ 1,095,492	$ 3,345,906
Relative percentage	67 %	33 %	100 %

	For the year ended December 31, 2021						
	For the year ended December 31, 2021						
	For the year ended December 31, 2021						
	For the year ended December 31, 2022						
	For the year ended December 31, 2022						
	For the year ended December 31, 2022						
	Midland Basin	Midland Basin	South Texas	Total	Midland Basin	South Texas	Total
	(in thousands)						
	(in thousands)						
	(in thousands)						
Oil production revenue							
Gas production revenue							
NGL production revenue							
Total							
Relative percentage	Relative percentage 78 %	22 %	100 %	Relative percentage 67 %		33 %	100 %

The Company recognizes oil, gas, and NGL production revenue at the point in time when control of the product transfers to the purchaser, which may differ depending on the applicable contractual terms. Transfer of control determines the presentation of transportation, gathering, processing, and other post-production expenses (“fees costs and other deductions”) within the accompanying statements of operations. Fees Costs and other deductions incurred by the Company prior to transfer of control are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations. When control is transferred, at or near the wellhead, sales are based on a wellhead market price that may be affected by fees and other deductions incurred by the purchaser subsequent to the transfer of control. In general, the Company generates production revenue from a combination of the following types of contracts:

- The Company sells oil and gas production at or near the wellhead and receives an agreed-upon market price from the purchaser. Under this type of arrangement, control transfers at or near the wellhead.
- The Company has certain processing arrangements that include the delivery of unprocessed gas to a midstream processor’s facility for processing. Upon completion of processing, the midstream processor purchases the NGLs and redelivers residue gas back to the Company in-kind. For the NGLs extracted during processing, the midstream processor remits payment to the Company. For the residue gas taken in-kind, the Company has separate sales contracts where control transfers at points downstream of the processing facility. The Company also has certain oil sales that occur at market locations downstream of the production area. Given the structure of these arrangements and where control transfers, the Company separately

recognizes fees costs and other deductions incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.

Significant judgments made in applying • The Company has certain arrangements where oil volumes are transported by railcar to purchasers. For these sales arrangements, the guidance in ASC Topic 606, *Revenue from Contracts with Customers,* relate Company generally delivers produced oil to customers at defined locations, including domestic rail terminal facilities primarily along the point in time Gulf Coast. Upon delivery, the Company is entitled to an agreed upon index price, net of pricing differentials for each barrel sold. The Company recognizes revenue when control transfers to purchasers in the customer and the Company has no further contractual obligation to the customer. Costs associated with the transportation of these oil volumes are recorded within the oil, gas, processing arrangements with midstream processors. and NGL production expense line item on the accompanying statements of operations.

The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with generally predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company’s performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied upon control transferring to a purchaser at the wellhead, inlet, or tailgate of the midstream processor’s processing facility, rail terminal, or other contractually specified delivery point. The For volumes sold at, or in close proximity to the wellhead, the time period between production and satisfaction of performance obligations is generally less than one day; thus, day. For volumes transported by rail, this period is generally less than two weeks. As of December 31, 2024, there are were no material unsatisfied or partially unsatisfied performance obligations at the end of the reporting period. obligations.

Revenue is recorded in the month when performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received 30 to 90 days after production has occurred. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the product. Estimated revenue due to the Company is recorded within the accounts receivable line item on the accompanying balance sheets until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of December 31, 2023 December 31, 2024, and 2022, 2023, were $175.3 $246.4 million and $184.5 $175.3 million, respectively. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser.

Note 3 – Equity

Stock Repurchase Program

During 2022, In June 2024, the Company’s Board of Directors approved re-authorized the Company’s existing Stock Repurchase Program authorizing to re-establish the Company Company’s authorization to repurchase up to $500.0 million in aggregate value of its common stock through December 31, 2024 December 31, 2027. The Stock Repurchase Program permits the Company to repurchase shares of its common stock from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws and subject to certain provisions of the Credit Agreement and the indentures governing the Senior Notes, as defined in *Note 5 – Long-Term Debt*. The timing, as well as the number and value of shares repurchased under the Stock Repurchase Program, will be determined by certain authorized officers of the Company at their discretion and will depend on a variety of factors, including the market price of the Company’s common stock, general market and economic conditions and applicable legal requirements. The value of shares authorized for repurchase by the Board of Directors does not require the Company to repurchase such shares or guarantee that such shares will be repurchased, and the Stock Repurchase Program may be suspended, modified, or discontinued at any time without prior notice. No assurance can be given that any particular number or dollar value of its shares will be repurchased by the Company.

The following table presents activity under the Company’s common stock repurchase activity for the years ended December 31, 2023, and 2022: Stock Repurchase Program:

		For the Years Ended December 31,		**For the Years Ended December 31,**
		For the Years Ended December 31,		
		For the Years Ended December 31,		
	2023			
		2024	**2023**	**2022**
		(in thousands, except per share data)		
		(in thousands, except per share data)		
		(in thousands, except per share data)		
Shares of common stock repurchased (1)	Shares of common stock repurchased (1)	1,771	6,931	1,365
Weighted-average price per share (2)				
Weighted-average price per share (2)				
Weighted-average price per share (2)				
Cost of shares of common stock repurchased (2) (3)				
Cost of shares of common stock repurchased (2) (3)				
Cost of shares of common stock repurchased (2) (3)				

(1) All repurchased shares of the Company’s common stock were retired upon repurchase.

(2) Amounts exclude excise taxes, commissions, and fees.

(3) Amounts may not calculate due to rounding.

As of the filing of this report, $214.9 December 31, 2024, $500.0 million remains remained available for repurchases of the Company’s outstanding common stock through December 31, 2024 December 31, 2027, under the Stock Repurchase Program.

Dividends

During 2023, 2024, the Company’s Board of Directors approved an increase to the Company’s fixed dividend to $0.72 $0.80 per share annually, to be paid in quarterly increments of $0.18 $0.20 per share, beginning which commenced in the first fourth quarter of 2024. During the year ended December 31, 2023 December 31, 2024, net cash dividends declared totaled $74.2 $87.1 million.

Warrants

On June 17, 2020, the Company issued warrants to purchase up to an aggregate of approximately 5.9 million shares, or approximately five percent of its then outstanding common stock, at an exercise price of $0.01 per share (“Warrants”). The Warrants became exercisable at the election of the holders on January 15, 2021, pursuant to the terms of the Warrant Agreement, dated June 17, 2020, and all of the Warrants were exercised prior to their expiration date of June 30, 2023.

The following table presents activity related to warrants exercised during the periods presented:

	For the Years Ended December 31,		
	2023	2022	2021
	(in thousands, except per share data)		
Warrants exercised	19	—	5,922
Shares of common stock issued as a result of cashless exercise of warrants	19	—	5,918
Weighted-average share price on exercise date	$ 29.09	$ —	$ 15.45

Note 4 – Income Taxes

The provision for income taxes consisted of the following:

	For the Years Ended December 31,					
	2023	2022	2021			
	2024	2023	2022			
	(in thousands)					
	(in thousands)					
	(in thousands)					
Current portion of income tax (expense) benefit						
Federal						
Federal						
Federal						
State						
Deferred portion of income tax expense						
Income tax expense						
Effective tax rate						
Effective tax rate						
Effective tax rate	10.5 %	20.3 %	21.5 %	20.3 %	10.5 %	20.3 %

The components of the net deferred tax liabilities are as follows:

	As of December 31,	
	2023	2022
	2024	2023
	(in thousands)	
	(in thousands)	
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties excluding asset retirement obligation liabilities		
Oil and gas properties excluding asset retirement obligation liabilities		
Oil and gas properties excluding asset retirement obligation liabilities		
Derivative assets		
Other		
Other		
Other		
Total deferred tax liabilities		
Deferred tax assets:		
Asset retirement obligation liabilities		
Asset retirement obligation liabilities		
Asset retirement obligation liabilities		
Credit carryover, net		
Credit carryover, net		
Credit carryover, net		
Asset retirement obligation liabilities		

Lease liabilities
Legal liabilities
Federal and state tax net operating loss carryovers
Legal liabilities
Equity compensation
Pension
Interest carryforward
Other
Interest carryforward
Other
Interest carryforward
Other
Total deferred tax assets
Valuation allowance
Net deferred tax assets
Net deferred tax liabilities
Current federal income tax refundable (payable)
Current federal income tax refundable (payable)
Current federal income tax refundable (payable)
Current state income tax refundable (payable)

As of December 31, 2023 December 31, 2024, the Company had utilized all of its remaining federal gross state net operating loss ("NOL") carryovers and had gross state NOL carryforwards of $74.0 $71.3 million. Other than in states with no NOL carryforward expiration, the Company's state NOL carryforwards expire between 2029 2034 and 2039. The Company's current valuation allowance includes an amount for state NOL carryforwards and state tax credits, which are expected to expire before they can be utilized.

The Company commissioned completed a multi-year R&D credit study in 2022, 2023, which was completed during 2023, and resulted in a favorable adjustment to the Company's effective tax rate for the year ended December 31, 2023, and a reduction of the Company's 2022 and 2023 tax obligations. obligation. After utilizing a portion of the credits for the 2022 2023 and 2023 2024 tax years, the recorded net carryover R&D credit, as of December 31, 2023 December 31, 2024, expected to be utilized in future periods totaled $56.1 million. $18.8 million. The R&D credits expire between 2037 2041 and 2043. 2044.

Income tax expense or benefit differs from the amount that would be provided calculated by applying the statutory United States federal income tax rate to income or loss before income taxes. These differences primarily relate to the effect of federal tax credits, state income taxes, changes in valuation allowances, excess tax benefits and deficiencies from stock-based compensation awards, tax deduction limitations on compensation of covered individuals, the cumulative impact effect of other smaller permanent differences, and can also reflect the cumulative effect of an enacted tax rate change, in the period of enactment, on the Company's net deferred tax asset and liability balances. These differences for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, are presented below:

	For the Years Ended December 31,		
	2023	**2022**	**2021**
	2024	**2023**	**2022**
	(in thousands)		
	(in thousands)		
	(in thousands)		
Federal statutory tax expense			
(Increase) decrease in tax resulting from:			
Net federal R&D tax credit			
Net federal R&D tax credit			
Net federal R&D tax credit			
Change in valuation allowance			
Change in valuation allowance			
Change in valuation allowance			
State tax (expense) benefit, net of federal effect			
State tax (expense) benefit, net of federal effect			
State tax (expense) benefit, net of federal effect			
Other			
Income tax expense			

Acquisitions, divestitures, drilling activity, and basis differentials, which impact the prices received for oil, gas, and NGLs, impact the apportionment of taxable income to the states where the Company owns oil and gas properties. Transporting oil from the location where it is produced to the different markets where it may be sold affects the apportionment of income taxes. As these factors change, the Company's state income tax rate changes. This change, when applied to the Company's total temporary differences, impacts the total state income tax expense reported. Items affecting state apportionment factors are evaluated upon completion of the prior year income tax return, after significant acquisitions and divestitures, if there are significant changes in drilling activity, or if estimated state revenue changes occur during the year.

For all years before 2020, 2021, the Company is generally no longer subject to United States federal or state income tax examinations by tax authorities.

The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. The Company does not expect a significant change to the recorded unrecognized tax benefits in 2024, except for any potential changes related to the Company's R&D credit study discussed above and any potential 2024 R&D credit claims. 2025.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in thousands)		
	(in thousands)		
	(in thousands)		
Beginning balance			
Additions based on tax positions related to current year			
Ending balance			
Ending balance			
Ending balance			

Note 5 – Long-Term Debt

Credit Agreement

On July 2, 2024, the Company and its lenders entered into the First Amendment to the Credit Agreement ("First Amendment") to amend certain provisions of the Credit Agreement to facilitate financing for the Uinta Basin Acquisition. On October 1, 2024, the Company and its lenders entered into the Second Amendment to the Credit Agreement ("Second Amendment") in conjunction with the closing of the Uinta Basin Acquisition, to, among other things: (i) increase the aggregate revolving lender commitments available under the Credit Agreement from $1.25 billion to $2.0 billion; (ii) extend the maturity date of the Credit Agreement, as discussed below; and (iii) modify certain other provisions reflective of the increased aggregate revolving lender commitments, increased Company size and scale, and extended maturity date. The Company's Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of $3.0 billion. As of December 31, 2023 December 31, 2024, the borrowing base and aggregate revolving lender commitments under the Credit Agreement were $2.5 $3.0 billion and $1.25 $2.0 billion, respectively. Refer to *Note 17 – Acquisitions* for the definition of the Uinta Basin Acquisition.

The revolving credit facility is secured by substantially all of the Company's proved oil and gas properties. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both the Company's proved oil and gas properties reflected in the Company's most recent reserve report; and commodity derivative contracts, each as determined by the Company's lender group. The next scheduled borrowing base redetermination date is April 1, 2024 scheduled to occur on April 1, 2025. The Credit Agreement is scheduled to mature on the earlier of August 2, 2027 (a) October 1, 2029 ("Stated Maturity Date"), or (b) 91 days prior to the maturity date of any of the Company's outstanding Senior Notes, as defined below, to the extent that, on or before such date, the respective Senior Notes in an amount exceeding $50.0 million have not been repaid, exchanged, repurchased, refinanced, or otherwise redeemed in full, and, if refinanced or exchanged, with a scheduled maturity date that is not earlier than at least 180 days after the Stated Maturity Date. The financial covenants under the Credit Agreement are discussed under *Covenants* below.

Interest and commitment fees associated with the revolving credit facility are accrued based on a borrowing base total revolving commitments utilization grid set forth in the Credit Agreement, and as presented in the table below. At the Company's election, borrowings under the Credit Agreement may be in the form of SOFR revolving loans, Alternate Base Rate ("ABR"), revolving loans, or Swingline loans. SOFR revolving loans accrue interest at SOFR plus the applicable margin from the utilization grid, and ABR revolving loans and Swingline loans accrue interest at a market-based floating rate, plus the applicable margin from the utilization grid. Commitment fees are accrued on the unused portion of the aggregate revolving lender commitment amount at rates from the utilization grid.

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
SOFR Loans	2.000 %	2.250 %	2.500 %	2.750 %	3.000 %
ABR Loans or Swingline Loans	1.000 %	1.250 %	1.500 %	1.750 %	2.000 %
Commitment Fee Rate	0.375 %	0.375 %	0.500 %	0.500 %	0.500 %

Total Revolving Commitments Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
SOFR Revolving Loans	1.750 %	2.000 %	2.250 %	2.500 %	2.750 %
ABR Revolving Loans or Swingline Loans	0.750 %	1.000 %	1.250 %	1.500 %	1.750 %

Commitment Fee Rate	0.375 %	0.375 %	0.500 %	0.500 %	0.500 %

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of February 8, 2024, December 31, 2023, and December 31, 2022: Agreement:

	As of February 8, 2024	As of December 31, 2023	As of December 31, 2022
	As of January 31, 2025	As of December 31, 2024	As of December 31, 2023
	(in thousands)		
	(in thousands)		
	(in thousands)		
Revolving credit facility (1)			
Letters of credit (2)			
Available borrowing capacity			
Total aggregate lender commitment amount			
Total aggregate lender revolving commitment amount			

(1) Unamortized deferred financing costs attributable to the revolving credit facility are presented as a component of the other noncurrent assets line item on the accompanying balance sheets and totaled $8.5 $18.7 million and $10.8 $8.5 million as of December 31, 2023 December 31, 2024, and 2022, 2023, respectively. These costs are being amortized over the term of the revolving credit facility Credit Agreement on a straight-line basis.

(2) Letters of credit outstanding reduce the amount available under the revolving credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes, net line item on the accompanying balance sheets as of December 31, 2023 December 31, 2024, and 2022, 2023, consisted of the following (collectively referred to as "Senior Notes"):

	As of December 31, 2023			As of December 31, 2022		
	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net
	(in thousands)					
5.625% Senior Notes due 2025	$ 349,118	$ 896	$ 348,222	$ 349,118	$ 1,528	$ 347,590
6.75% Senior Notes due 2026	419,235	1,868	417,367	419,235	2,569	416,666
6.625% Senior Notes due 2027	416,791	2,395	414,396	416,791	3,172	413,619
6.5% Senior Notes due 2028	400,000	4,651	395,349	400,000	5,665	394,335
Total	$ 1,585,144	$ 9,810	$ 1,575,334	$ 1,585,144	$ 12,934	$ 1,572,210

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices that may include a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes. Fees incurred upon issuance of each series of Senior Notes are being amortized as deferred financing costs over the life of the respective notes, unless earlier redeemed or retired, in which case amortization has been proportionately accelerated.

2025 Senior Notes. On May 21, 2015, the Company issued $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025, at par, which mature on June 1, 2025 ("2025 Senior Notes"). The Company received net proceeds of $491.0 million after deducting fees of $9.0 million.

	As of December 31, 2024			As of December 31, 2023		
	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net
	(in thousands)					
5.625% Senior Notes due 2025	$ —	$ —	$ —	$ 349,118	$ 896	$ 348,222
6.75% Senior Notes due 2026	419,235	1,168	418,067	419,235	1,868	417,367
6.625% Senior Notes due 2027	416,791	1,618	415,173	416,791	2,395	414,396
6.5% Senior Notes due 2028	400,000	3,636	396,364	400,000	4,651	395,349
6.75% Senior Notes due 2029	750,000	10,489	739,511	—	—	—
7.0% Senior Notes due 2032	750,000	10,872	739,128	—	—	—
Total	$ 2,736,026	$ 27,783	$ 2,708,243	$ 1,585,144	$ 9,810	$ 1,575,334

2026 Senior Notes. On September 12, 2016, the Company issued $500.0 million in aggregate principal amount of 6.75% Senior Notes due 2026, at par, which mature on September 15, 2026 ("2026 Senior Notes"). The Company received net proceeds of $491.6 million after deducting fees of $8.4 million.

2027 Senior Notes. On August 20, 2018, the Company issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027, at par, which mature on January 15, 2027 ("2027 Senior Notes"). The Company received net proceeds of $492.1 million after deducting fees of $7.9 million.

2028 Senior Notes. On June 23, 2021, the Company issued $400.0 million in aggregate principal amount of 6.5% Senior Notes due 2028, at par, which mature on July 15, 2028 ("2028 Senior Notes"). The Company received net proceeds of $392.8 million after deducting fees of $7.2 million.

2029 Senior Notes. On July 25, 2024, the Company issued $750.0 million in aggregate principal amount of 6.75% Senior Notes due 2029, at par, which mature on August 1, 2029. The Company received net proceeds of $738.5 million after deducting fees of $11.5 million.

2032 Senior Notes. On July 25, 2024, the Company issued $750.0 million in aggregate principal amount of 7.0% Senior Notes due 2032, at par, which mature on August 1, 2032. The Company received net proceeds of $738.5 million after deducting fees of $11.5 million.

Senior Notes Activity

On August 26, 2024, the Company redeemed the $349.1 million of aggregate principal amount outstanding of its 2025 Senior Notes, pursuant to the terms of the indenture governing the 2025 Senior Notes, which provided for a redemption price equal to 100 percent of the principal amount outstanding of the 2025 Senior Notes on the date of redemption, plus accrued and unpaid interest. Upon redemption, the Company recorded a loss on extinguishment of debt of $0.5 million related to the accelerated expense recognition of the remaining unamortized deferred financing costs. The Company canceled all redeemed 2025 Senior Notes upon settlement.

On February 14, 2022, the Company redeemed the $104.8 million of aggregate principal amount outstanding of its 5.0% Senior Notes due 2024 ("2024 Senior Notes"), with cash on hand, pursuant to the terms of the indenture governing the 2024 Senior Notes, which provided for a redemption price equal to 100 percent of the principal amount of the 2024 Senior Notes on the date of redemption, plus accrued and unpaid interest. Upon redemption, the Company accelerated the amortization of all remaining previously unamortized deferred financing costs. The Company canceled all redeemed 2024 Senior Notes upon settlement.

On June 23, 2021, the Company issued $400.0 million in aggregate principal amount of its 2028 The Senior Notes as described above. The net proceeds are unsecured senior obligations and rank equal in right of $392.8 million were used to repurchase $193.1 million and $172.3 million of outstanding principal amount payment with all of the Company's 6.125% existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. The Company may redeem some or all of its Senior Notes due 2022 ("2022 prior to their maturity at redemption prices that may include a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes") and 2024 Notes. Fees incurred upon issuance of each series of Senior Notes respectively, through a cash tender offer ("Tender Offer"), and to redeem the remaining $19.3 million of 2022 Senior Notes not repurchased are being amortized as part of the Tender Offer ("2022 Senior Notes Redemption"). The Company paid total consideration, excluding accrued interest, of $385.3 million, and recorded a net loss on extinguishment of debt of $2.1 million for the year ended December 31, 2021, which included the accelerated expense recognition of $1.5 million of the remaining unamortized deferred financing costs and $0.6 million over the life of net premiums. The Company canceled all repurchased and the respective notes, unless earlier redeemed 2022 Senior Notes and 2024 Senior Notes upon settlement. or retired, in which case amortization has been proportionately accelerated.

Senior Secured Notes Activity

On June 17, 2022, the Company redeemed all of the $446.7 million of aggregate principal amount outstanding of its 10.0% Senior Secured Notes due 2025 ("2025 Senior Secured Notes"), with cash on hand, at a redemption price equal to 107.5 percent of the principal amount outstanding on the date of the redemption, plus accrued and unpaid interest. Upon redemption, the Company recorded a net loss on extinguishment of debt of $67.2 million which included $33.5 million of premium paid, $26.3 million of accelerated expense recognition of the unamortized debt discount, and $7.4 million of accelerated expense recognition of the remaining unamortized deferred financing costs. The Company canceled all redeemed 2025 Senior Secured Notes upon settlement.

On July 1, 2021, the 1.50% Senior Secured Convertible Notes ("2021 Senior Secured Convertible Notes") matured, and on that day, the Company used borrowings under its revolving credit facility to retire, at par, the outstanding principal amount of $65.5 million.

Covenants

The Company is subject to certain financial and non-financial covenants under the Credit Agreement and the indentures governing the Senior Notes that, among other terms, limit the Company's ability to incur additional indebtedness, make restricted payments including dividends, sell assets, create liens that secure debt, enter into transactions with affiliates, make certain investments, or merge or consolidate with other entities. The financial covenants under the Credit Agreement require that the Company's (a) total funded debt, as defined in the Credit Agreement, to 12-month trailing adjusted EBITDAX ratio cannot be greater than 3.50 to 1.00 on the last day of each fiscal quarter; and (b) adjusted current ratio, as defined in the Credit Agreement, cannot be less than 1.00 to 1.00 as of the last day of any fiscal quarter. The Company was in compliance with all covenants under the Credit Agreement and the indentures governing the Senior Notes as of December 31, 2023 December 31, 2024, and through the filing of this report. Refer to the First Amendment and Second Amendment to the Credit Agreement, included as Exhibits 10.4 and 10.5, respectively, to this report, for additional detail on the Company's covenants under the Credit Agreement and indentures governing the Senior Notes.

Capitalized Interest

Capitalized interest costs for the years ended December 31, 2023 December 31, 2024, 2023, and 2022, and 2021, totaled $25.5 million, $20.4 million, $17.6 million, and $15.0 $17.6 million, respectively. The amount of interest the Company capitalizes generally fluctuates based on the amount borrowed, the Company's capital program, and the timing and amount of costs associated with capital projects that are considered in progress. Capitalized interest costs are included in total costs incurred. Please refer Refer to *Costs Incurred* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional information.

Note 6 – Commitments and Contingencies

Commitments

As of December 31, 2023 December 31, 2024, the Company had entered into various types of agreements as discussed below. The following table presents the annual minimum payments related to these agreements for the next five years, and the total minimum payments thereafter as of December 31, 2023 December 31, 2024:

For the Years Ending December 31,		Amount
		(in thousands)
2024	$	74,992
2025		52,175
2026		28,133
2027		13,791
2028		12,461
Thereafter		14,655
Total	$	196,207

	For the Years Ending December 31,						
	2025	2026	2027	2028	2029	Thereafter	Total
				(in thousands)			
Delivery commitments (1) (2)	$ 48,002	$ 28,679	$ 25,814	$ 20,879	$ —	$ —	$ 123,374
Drilling rig contracts (3)	34,729	—	—	—	—	—	34,729
Office space leases (4)	4,926	3,785	3,272	3,361	2,571	9,321	27,236
Electrical power purchase contracts	13,268	13,945	15,735	16,683	2,209	—	61,840
Compression service contracts	11,916	9,677	7,967	3,296	—	—	32,856
Railcar agreements	10,080	7,993	7,775	2,938	1,469	—	30,255
Sand purchase agreement (5)	16,800	4,200	—	—	—	—	21,000
Other (6)	15,159	13,197	7,425	1,293	—	—	37,074
Total	$ 154,880	$ 81,476	$ 67,988	$ 48,450	$ 6,249	$ 9,321	$ 368,364

Drilling Rig Contracts. Note: The Company has drilling rig contracts in place to facilitate its drilling plans. As of December 31, 2023, the Company's drilling rig commitments totaled $19.1 million under contract terms extending through the third quarter of 2024. If all of these contracts were terminated as of December 31, 2023, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay $12.3 million in early termination fees. Subsequent to December 31, 2023, the Company entered into a new drilling rig contract, and as of the filing of this report, the Company's drilling rig commitments totaled $14.5 million under contract terms extending through the third quarter of 2024. If all of these contracts were terminated as of the filing of this report, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay $8.9 million in early termination fees. No material expenses related to early termination or standby fees were incurred by the Company during the year ended December 31, 2023, and the Company does not expect to incur material penalties or shortfalls with regard to its drilling rig contracts during 2024.commitments.

Delivery Commitments. (1) The Company has gathering, processing, transportation throughput, terminal services, transloading, and delivery commitments with various third-parties that require delivery of a minimum amount of oil and produced water. As of December 31, 2023 December 31, 2024, the Company had commitments to deliver a minimum of 5 46 MMBbl of oil through July December of 2026 2028, and 11 3 MMBbl of produced water through June of 2027. Certain of these oil delivery commitments may be fulfilled with the same single barrel of oil. The Company would be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments under certain agreements. As Additionally, one of December 31, 2023 the contracts does not have a minimum volume commitment associated with it, however, as of December 31, 2024, the Company would owe a cancellation fee of $3.4 million if the Company failed to deliver any product, as applicable, the aggregate undiscounted deficiency payments would total approximately $11.5 million. This amount does not include deficiency payment estimates associated with approximately 1 MMBbl of future oil delivery commitments where the Company cannot predict with accuracy the amount and timing of these payments, as such payments are dependent upon the price of oil in effect at the time of settlement. agreement was terminated.

(2) The Company expects to fulfill the delivery commitments from a combination of production from existing productive wells, future development of net proved undeveloped reserves, and future development of resources not yet characterized as proved reserves. Under certain of the Company's commitments, if the Company is unable to deliver the minimum quantity from its production, it may deliver production acquired from third-parties to satisfy its minimum volume commitments.

(3) As of December 31, 2024, the filing Company's drilling rig commitments had contract terms extending through the fourth quarter of this report, 2025. If all of these contracts were terminated as of December 31, 2024, the Company does not expect would avoid a portion of the contractual service commitments; however, the Company would be required to incur pay $24.0 million in early termination fees. No material shortfalls with regard expenses related to these commitments. early termination or standby fees were incurred by the Company during the year ended December 31, 2024.

Office Leases. (4) The Company leases office space under various operating leases, totaling $33.3 million, including maintenance, with certain terms extending into 2033. Rent expense was $2.5 million for each of the years ended December 31, 2023 December 31, 2024, 2022, and 2021, 2023, and was $2.5 million, $3.5 million and $4.8 million, respectively. for the year ended December 31, 2022.

Electrical Power Purchase Contracts. (5) As If the Company terminated the agreement as of December 31, 2023 December 31, 2024, the Company had fixed price contracts for would avoid a portion of the contractual purchase of electrical power through March of 2029 with a total remaining obligation of $41.8 million. commitment; however, the Company would be required to pay an $8.0 million penalty.

Sand Purchase Commitment. (6) As Primarily consists of December 31, 2023, the Company had a sand purchase agreement with a minimum commitment of $46.8 million through March of 2026. As of December 31, 2023, if the Company failed to purchase the minimum amount required by the contract, it would be subject to penalties of up to $10.0 million. As of the filing of this report, the Company does not expect to incur penalties with regard to this agreement.

Compression Service Contracts. As of December 31, 2023, the Company had compression service contracts with terms extending through 2027 for equipment being used in field operations with a total remaining obligation of $19.5 million.

Miscellaneous Contracts and Leases. As of December 31, 2023, the Company had miscellaneous contracts and leases totaling $24.2 million, primarily related to IT contracts, water purchase agreements, and vehicle leases, with terms extending through 2027. leases.

Drilling and Completion Commitments. As of December 31, 2023 December 31, 2024, the Company had an agreement that includes minimum drilling and completion footage requirements on certain existing leases. If these minimum requirements are not satisfied by March 31, 2024 March 31, 2026, the Company will be required to pay liquidated damages based on the difference between the actual footage drilled and completed and the minimum requirements. As of December 31, 2023 December 31, 2024, the liquidated damages could range from zero to a maximum of $8.3 $37.2 million, with the maximum exposure assuming no additional development activity occurred occurs prior to March 31, 2024 March 31, 2026. As of the filing of this report, the Company does not expect to incur material liquidated damages with regard to this agreement.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the anticipated results of any pending litigation and claims are not expected to have a material effect on the results of operations, the financial position, or the cash flows of the Company.

Note 7 – Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company regularly enters into commodity derivative contracts to mitigate a portion of its exposure to oil, gas, and NGL price volatility and location differentials, and the associated effect on cash flows. All commodity derivative contracts that the Company enters into are for other-than-trading purposes. The Company's commodity derivative contracts consist of price swap and collar arrangements for oil and gas production, and price swap arrangements for NGL production. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap price, the Company receives the difference between the index price and the agreed upon swap price. If the index price is higher than the swap price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index price and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The Company has entered into fixed price oil and gas basis swaps in order to mitigate exposure to adverse pricing differentials between certain industry benchmark prices and the actual physical pricing points where the Company's production is sold. As of December 31, 2023 December 31, 2024, the Company had basis swap contracts with fixed price differentials between:

- NYMEX WTI and Argus WTI Midland ("WTI Midland") for a portion of its Midland Basin oil production with sales contracts that settle at WTI Midland prices;
- NYMEX WTI and Argus WTI Houston Magellan East Houston Terminal ("WTI Houston MEH") for a portion of its South Texas and Uinta Basin oil production with sales contracts that settle at WTI Houston MEH prices;
- NYMEX HH and Inside FERC West Texas ("IF Waha") for a portion of its Midland Basin gas production with sales contracts that settle at IF Waha prices; and
- NYMEX HH and Inside FERC Houston Ship Channel ("IF HSC") for a portion of its South Texas gas production with sales contracts that settle at IF HSC prices.

The Company has also entered into oil swap contracts to fix the differential in pricing between the NYMEX calendar month average and the physical crude oil delivery month ("Roll Differential") in which the Company pays the periodic variable Roll Differential and receives a weighted-average fixed price differential. The weighted-average fixed price differential represents the amount of net addition (reduction) to delivery month prices for the notional volumes covered by the swap contracts.

As of December 31, 2023 December 31, 2024, the Company had commodity derivative contracts outstanding through the fourth first quarter of 2025 2027 as summarized in the table below:

	Contract Period
	Contract Period
	Contract Period
	First Quarter
	First Quarter
	First Quarter
	2024
	2024
	2024
	2025
	2025
	2025
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	

Swaps
Swaps
Swaps
ICE Brent Volumes
ICE Brent Volumes
ICE Brent Volumes
NYMEX WTI Volumes
NYMEX WTI Volumes
NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
Collars
Collars
Collars
NYMEX WTI Volumes
NYMEX WTI Volumes
NYMEX WTI Volumes
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Basis Swaps
Basis Swaps
Basis Swaps
WTI Midland-NYMEX WTI Volumes
WTI Midland-NYMEX WTI Volumes
WTI Midland-NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
WTI Houston MEH-NYMEX WTI Volumes
WTI Houston MEH-NYMEX WTI Volumes
WTI Houston MEH-NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
Roll Differential Swaps
Roll Differential Swaps
Roll Differential Swaps
NYMEX WTI Volumes
NYMEX WTI Volumes
NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price

Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):

Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):

Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):

Swaps
Swaps
Swaps
NYMEX HH Volumes
NYMEX HH Volumes
NYMEX HH Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
IF Waha Volumes
IF Waha Volumes
IF Waha Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
Collars
Collars
Collars
NYMEX HH Volumes
NYMEX HH Volumes
NYMEX HH Volumes
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Basis Swaps
Basis Swaps
Basis Swaps
IF Waha-NYMEX HH Volumes
IF Waha-NYMEX HH Volumes
IF Waha-NYMEX HH Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
IF HSC-NYMEX HH Volumes
IF HSC-NYMEX HH Volumes
IF HSC-NYMEX HH Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price

NGL Derivatives (volumes in MBbl and prices in $ per Bbl):

NGL Derivatives (volumes in MBbl and prices in $ per Bbl):

NGL Derivatives (volumes in MBbl and prices in $ per Bbl):

Swaps
Swaps
Swaps
OPIS Propane Mont Belvieu Non-TET Volumes
OPIS Propane Mont Belvieu Non-TET Volumes

OPIS Propane Mont Belvieu Non-TET Volumes	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
OPIS Normal Butane Mont Belvieu Non-TET Volumes	
OPIS Normal Butane Mont Belvieu Non-TET Volumes	
OPIS Normal Butane Mont Belvieu Non-TET Volumes	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
OPIS Isobutane Mont Belvieu Non-TET Volumes	
OPIS Isobutane Mont Belvieu Non-TET Volumes	
OPIS Isobutane Mont Belvieu Non-TET Volumes	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
Weighted-Average Contract Price	

Commodity Derivative Contracts Entered Into Subsequent to December 31, 2023 December 31, 2024

Subsequent to December 31, 2023 December 31, 2024, and through the filing of this report, the Company entered into the following commodity derivative contracts:

	Contract Period
	Contract Period
	Contract Period
	First Quarter
	First Quarter
	First Quarter
	2024
	2024
	2024
	2025
	2025
	2025
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	
Oil Derivatives (volumes in MBbl and prices in $ per Bbl):	
Swaps	
Swaps	
Swaps	
NYMEX WTI Volumes	
NYMEX WTI Volumes	
NYMEX WTI Volumes	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
Weighted-Average Contract Price	
Collars	
Collars	
Collars	
NYMEX WTI Volumes	
NYMEX WTI Volumes	
NYMEX WTI Volumes	
Weighted-Average Floor Price	
Weighted-Average Floor Price	

Weighted-Average Floor Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Basis Swaps
Basis Swaps
Basis Swaps
WTI Midland-NYMEX WTI Volumes
WTI Midland-NYMEX WTI Volumes
WTI Midland-NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
WTI Houston MEH-NYMEX WTI Volumes
WTI Houston MEH-NYMEX WTI Volumes
WTI Houston MEH-NYMEX WTI Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):
Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):
Gas Derivatives (volumes in BBtu and prices in $ per MMBtu):
Swaps
Swaps
Swaps
NYMEX HH Volumes
NYMEX HH Volumes
NYMEX HH Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
IF HSC Volumes
IF HSC Volumes
IF HSC Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
Collars
Collars
Collars
NYMEX HH Volumes
NYMEX HH Volumes
NYMEX HH Volumes
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Floor Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Weighted-Average Ceiling Price
Basis Swaps

Basis Swaps
Basis Swaps
IF HSC-NYMEX HH Volumes
IF HSC-NYMEX HH Volumes
NGL Derivatives (volumes in MBbl and prices in $ per Bbl):
IF HSC-NYMEX HH Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
NGL Derivatives (volumes in MBbl and prices in $ per Bbl):
NGL Derivatives (volumes in MBbl and prices in $ per Bbl):
NGL Derivatives (volumes in MBbl and prices in $ per Bbl):
Swaps
Swaps
Swaps
OPIS Propane Mont Belvieu Non-TET Volumes
OPIS Propane Mont Belvieu Non-TET Volumes
OPIS Propane Mont Belvieu Non-TET Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
OPIS Normal Butane Mont Belvieu Non-TET Volumes
OPIS Normal Butane Mont Belvieu Non-TET Volumes
OPIS Normal Butane Mont Belvieu Non-TET Volumes
OPIS Ethane Mont Belvieu Non-TET Volumes
OPIS Ethane Mont Belvieu Non-TET Volumes
OPIS Ethane Mont Belvieu Non-TET Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price
OPIS Isobutane Mont Belvieu Non-TET Volumes
OPIS Isobutane Mont Belvieu Non-TET Volumes
OPIS Isobutane Mont Belvieu Non-TET Volumes
Weighted-Average Contract Price
Weighted-Average Contract Price
Weighted-Average Contract Price

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company does not designate its commodity derivative contracts as hedging instruments. The fair value of the commodity derivative contracts at December 31, 2023 December 31, 2024, and 2022, 2023, was a net asset of $57.1 million $38.3 million and $15.8 million $57.1 million, respectively.

The following table details the fair value of commodity derivative contracts recorded in the accompanying balance sheets, by category:

	As of December 31, 2023	**As of December 31, 2022**
	As of December 31, 2024	**As of December 31, 2023**
	(in thousands)	
	(in thousands)	
	(in thousands)	
Derivative assets:		
Current assets		
Current assets		
Current assets		
Noncurrent assets		

Total derivative assets	
Derivative liabilities:	
Current liabilities	
Current liabilities	
Current liabilities	
Noncurrent liabilities	
Total derivative liabilities	

Offsetting of Derivative Assets and Liabilities

As of December 31, 2023 December 31, 2024, and 2022, 2023, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts:

	Derivative Assets as of		Derivative Assets as of		Derivative Liabilities as of	Derivative Assets as of	Derivative Liabilities as of
	December 31, 2023	December 31, 2022	December 31, 2023		December 31, 2022		
	December 31, 2024	December 31, 2023	December 31, 2024		December 31, 2023		
	(in thousands)						
	(in thousands)						
	(in thousands)						
Gross amounts presented in the accompanying balance sheets							
Amounts not offset in the accompanying balance sheets							
Net amounts							

The Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring such amounts in accumulated other comprehensive loss. The Company had no commodity derivative contracts designated as hedging instruments for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021. Please refer 2022. Refer to *Note 8 – Fair Value Measurements* for more information regarding the Company's derivative instruments, including its valuation techniques.

The following table summarizes the commodity components of the net derivative settlement (gain) loss and the net derivative (gain) loss line items presented within the accompanying statements of cash flows and the accompanying statements of operations, respectively:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in thousands)		
	(in thousands)		
	(in thousands)		
Net derivative settlement (gain) loss:			
Oil contracts			
Oil contracts			
Oil contracts			
Gas contracts			
NGL contracts			
Total net derivative settlement (gain) loss:			
Net derivative (gain) loss:			
Net derivative (gain) loss:			
Net derivative (gain) loss:			
Oil contracts			
Oil contracts			

Oil contracts	
Gas contracts	
NGL contracts	
Total net derivative (gain) loss:	

Credit Related Contingent Features

As of December 31, 2023 December 31, 2024, all of the Company's derivative counterparties were members of the Company's Credit Agreement lender group. The Company does not enter into derivative contracts with counterparties that are not part of the lender group. Under the Credit Agreement, the Company is required to provide mortgage liens on assets having a value equal to at least 85 percent of the total PV-9, as defined in the Credit Agreement, of the Company's proved oil and gas properties evaluated in the most recent reserve report. Collateral securing indebtedness under the Credit Agreement also secures the Company's derivative agreement obligations.

Note 8 – Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value on a recurring basis in the accompanying balance sheets and where they are classified within the fair value hierarchy:

	As of December 31, 2023			As of December 31, 2022		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Assets:						
Derivatives (1)	$ —	$ 65,114	$ —	$ —	$ 73,142	$ —
Liabilities:						
Derivatives (1)	$ —	$ 8,062	$ —	$ —	$ 57,323	$ —

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.

	As of December 31, 2024			As of December 31, 2023		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in thousands)					
Assets:						
Derivatives	$ —	$ 52,495	$ —	$ —	$ 65,114	$ —
Liabilities:						
Derivatives	$ —	$ 14,200	$ —	$ —	$ 8,062	$ —

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the

Company as well as the general classification of such instruments pursuant to the above fair value hierarchy. Please refer Refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on the Company's policies for determining fair value for the categories discussed below.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivative instruments. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The commodity derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any commodity derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current revolving credit facility margins, and any change in such margins since the last measurement date.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Please refer Refer to *Note 7 – Derivative Financial Instruments* for more information regarding the Company's derivative instruments.

Oil Acquisition of proved and Gas Properties unproved properties

Assets acquired and Other Property liabilities assumed under transactions that do not meet the criteria of a business combination under ASC Topic 805, *Business Combinations* are accounted for as an asset acquisition and Equipment

The Company had no assets included in total property and equipment, net, measured at are recorded based on the fair value as of December 31, 2023, or 2022.

No impairment expense was recorded for the year ended December 31, 2023. Impairment expense for the years ended December 31, 2022, and 2021, was $7.5 million and $35.0 million, respectively, and consisted of unproved property abandonments and impairments related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. The balances in the unproved oil and gas properties line item total consideration transferred on the accompanying balance sheets as of December 31, 2023, and 2022, are recorded at carrying value. Please refer acquisition date using the lowest observable inputs available. Refer to *Note 1 17 – Summary of Significant Accounting Policies Acquisitions* for information on the Company's policies for determining fair value of its oil and gas producing properties and related impairment expense. additional discussion.

Long-Term Debt

The following table reflects the fair value of the Company's Senior Notes obligations measured using Level 1 inputs based on quoted secondary market trading prices. These notes were not presented at fair value on the accompanying balance sheets as of December 31, 2023 December 31, 2024, or 2022, 2023, as they were recorded at carrying value, net of any unamortized deferred financing costs. Please refer Refer to *Note 5 – Long-Term Debt* for additional information.

	As of December 31,							
	2023		2022					
	2024		2023					
Principal Amount	Principal Amount	Fair Value	Principal Amount	Fair Value	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)							
	(in thousands)							
	(in thousands)							
5.625% Senior Notes due 2025								
6.75% Senior Notes due 2026								
6.625% Senior Notes due 2027								
6.5% Senior Notes due 2028								
6.75% Senior Notes due 2029								
7.0% Senior Notes due 2032								

The carrying value of the Company's revolving credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

Note 9 – Earnings Per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities.

For the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, potentially dilutive securities for this calculation consisted primarily of non-vested RSUs and contingent PSUs, and Warrants, all of which were measured using the treasury stock method. The Warrants became exercisable at the election of the holders on January 15, 2021, and all of the Warrants were exercised prior to their expiration date of June 30, 2023. The Warrants were included as potentially dilutive securities on an adjusted weighted-average basis for the portions of the years ended December 31, 2023, 2022, and 2021, during which they were outstanding but not yet exercised. Please refer to *Note 3 – Equity* for additional detail regarding the terms of the Warrants.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer

Refer to *Note 10 – Compensation Plans* under the heading *Performance Share Units*. for additional detail on RSUs and PSUs.

The following table sets forth the calculations of basic and diluted net income per common share:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in thousands, except per share data)		
	(in thousands, except per share data)		
	(in thousands, except per share data)		
Net income			
Basic weighted-average common shares outstanding			
Basic weighted-average common shares outstanding			
Basic weighted-average common shares outstanding			
Dilutive effect of non-vested RSUs, contingent PSUs, and other			
Dilutive effect of Warrants			
Diluted weighted-average common shares outstanding			
Diluted weighted-average common shares outstanding			
Diluted weighted-average common shares outstanding			
Basic net income per common share			
Basic net income per common share			
Basic net income per common share			
Diluted net income per common share			

Note 10 – Compensation Plans

The Company may grant various types of both short-term and long-term incentive-based awards under its compensation plans, such as time-based cash awards, performance-based cash awards, and equity awards to eligible employees. Additionally, the Company grants stock-based compensation to its Board of Directors, and provides an employee stock purchase plan and a 401(k) plan to eligible employees.

As of December 31, 2023 December 31, 2024, approximately 2.8 million 1.9 million shares of common stock were available for grant under the Equity Plan. The issuance of a direct share benefit, such as a share of common stock, a stock option, a restricted share, an RSU or a PSU, counts as one share against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as two shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier.

Performance Share Units

The Company has granted PSUs to eligible employees as part of its Equity Plan. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on certain criteria over a three-year performance period. PSUs generally vest on the third anniversary of the grant date or upon other triggering events as set forth in the Equity Plan. Employees who meet retirement eligibility criteria, as defined by the applicable grant agreement, on the grant date of a PSU award vest in pro-rata increments on a daily basis over the three-year performance period beginning at the grant date, and any non-vested portions of a PSU award will be forfeited if the employee leaves the Company.

The fair value of PSUs is measured at the grant date using a stochastic Monte Carlo simulation using geometric Brownian motion ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for each iteration. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or

the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the path the stock price may take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three-year vesting period, as well as the volatilities and dividend yields yield for each of the Company's peers.

For PSUs granted in 2024, 2023, and 2022, which the Company determined to be equity awards, settlement will be determined based on a combination of the following criteria measured over the three-year performance period: the Company's Total Shareholder Return ("TSR") relative to the TSR of certain peer companies, the Company's absolute TSR, free cash flow ("FCF") generation, and the achievement of certain ESG targets, in each case as defined by the award agreement. The relative and absolute TSR portions of the fair value of the PSUs granted in 2024, 2023, and 2022, were measured on the grant date using the GBM Model. The portion of the awards associated with FCF generation and ESG performance conditions assumes that target amounts will be met at the end of the performance period. As a portion of these awards depends on performance-based settlement criteria, compensation expense may be adjusted in future periods as the expected number of shares of the Company's common stock issued to settle the units increases or decreases based on the Company's expected FCF generation and achievement of certain ESG targets.

The Company initially records compensation expense associated with the issuance of PSUs based on the fair value of the awards as of the grant date and may adjust compensation expense in future periods as discussed above. Compensation expense for PSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for PSUs was $5.5 million, $2.8 million, $2.6 million, and $6.0 $2.6 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively. As of December 31, 2023 December 31, 2024, there was $8.6 $13.9 million of total unrecognized expense related to non-vested PSUs, which is being amortized through mid-2026. mid-2027.

The fair value of PSUs granted in 2024, 2023, and 2022, was $7.7 million $9.9 million, $7.7 million, and $7.4 million, respectively. The fair value of PSUs that vested during the years ended December 31, 2022, and 2021, was $12.3 million and $8.4 million, respectively.

A summary of activity is presented in the following table:

	For the Years Ended December 31,												
	2023			2022		2021							
	2024			2023		2022							
	PSUs (1)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)	PSUs (1)	Weighted-Average Grant-Date Fair Value (2)
Non-vested at beginning of year													
Granted													
Vested													
Forfeited													
Non-vested at end of year													

(1) The number of PSUs presented assumes a multiplier of one. The actual final number of shares of common stock to be issued at the end of the three-year performance period will range from zero to two times the number of PSUs awarded depending on the three-year performance multiplier.

(2) Amounts represent price per unit.

A summary of the shares of common stock issued to settle PSUs is presented in the table below:

	For the Years Ended December 31,	
	2022	2021
Shares of common stock issued to settle PSUs (1)	1,004,410	347,742
Less: shares of common stock withheld for income and payroll taxes	(349,487)	(112,919)
Net shares of common stock issued	654,923	234,823
Multiplier earned	2.0	1.0

(1) During the year years ended December 31, 2023 December 31, 2024, and 2023, there were no shares of common stock issued to settle PSUs. During the years year ended December 31, 2022, and 2021, the Company settled PSUs that were granted in 2019, and 2018, respectively. which earned a 2.0 times multiplier. The Company and all eligible recipients in 2022 and 2021 mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings, as provided for in the Equity Plan and applicable award agreements. After withholding 349,487 shares to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs, 654,923 shares of the Company's common stock were issued in accordance with the terms of the applicable PSU awards. The fair value of PSUs that vested during the year ended December 31, 2022, was $12.3 million.

Employee Restricted Stock Units

The Company has granted RSUs to eligible employees as part of its Equity Plan. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. RSUs generally vest in one-third increments on each anniversary of the applicable grant date over the applicable vesting period or upon other triggering events as set forth in the Equity Plan. Employees who meet retirement eligibility criteria, as defined by the applicable grant agreement, at the time an RSU award is granted generally vest in six-month increments over the applicable vesting period beginning at the grant date.

Retirement eligible employees must stay with the Company through the entire six-month vesting period to receive that increment of vesting and any non-vested portions of an RSU award will be forfeited when the employee leaves the Company.

The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the grant date. The fair value of an RSU is equal to the closing price of the Company's common stock on the grant date. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for RSUs for the years ended December 31, 2023 December 31, 2024, 2023, and 2022, and 2021, was $16.7 million, $14.8 million, $13.5 million, and $10.2 $13.5 million, respectively. As of December 31, 2023 December 31, 2024, there was $25.7 $29.7 million of total unrecognized compensation expense related to non-vested RSUs, which is being amortized through mid-2026. mid-2027.

The fair value of RSUs granted to eligible employees in 2024, 2023 and 2022, and 2021, was $20.2 million $21.9 million, $18.0 $20.2 million, and $17.0 $18.0 million, respectively, and the fair value of RSUs that vested during the years ended December 31, 2023 December 31, 2024, 2023, and 2022, and 2021, was $15.3 million, $13.5 million, and $11.2 million, and $9.3 million, respectively.

A summary of activity is presented in the following table:

	For the Years Ended December 31,												
		2023		2022		2021							
		2024		2023		2022							
	RSUs	RSUs	Weighted-Average Grant-Date Fair Value (1)	RSUs	Weighted-Average Grant-Date Fair Value (1)	RSUs	Weighted-Average Grant-Date Fair Value (1)	RSUs	Weighted-Average Grant-Date Fair Value (1)	RSUs	Weighted-Average Grant-Date Fair Value (1)	RSUs	Weighted-Average Grant-Date Fair Value (1)
Non-vested at beginning of year													
Granted													
Vested													
Forfeited													
Non-vested at end of year													

(1) Amounts represent price per unit.

A summary of the shares of common stock issued to settle RSUs is presented in the table below:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
Shares of common stock issued to settle RSUs (1)			
Less: shares of common stock withheld for income and payroll taxes			
Net shares of common stock issued			

(1) During the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, the Company issued shares of common stock to settle RSUs that related to awards granted in previous years. The Company and all eligible recipients in 2024 and 2022, and a majority of eligible recipients in 2023, and all eligible recipients in 2022 and 2021, mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements.

Director Shares

In 2024, 2023, 2022, and 2021, 2022, the Company issued a total of 39,557, 56,872, 29,471, and 60,510 29,471 shares, respectively, of its common stock to its non-employee directors under the Equity Plan. For the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, the Company recorded $1.9 million, $1.6 million, $1.5 million, and $1.2 $1.5 million, respectively, of compensation expense related to director shares. All shares issued to non-employee directors fully vested on December 31 of during the year in which they were granted.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation, subject to a maximum of 2,500 shares per offering period and a maximum of $25,000 in value related to purchases for each calendar year. The purchase price of the common stock is 85 percent of the lower of the trading price of the common stock on either the first or last day of the six-month offering period. The ESPP is intended to qualify as an "employee stock purchase plan" under Section 423 of the IRC.

A total of 97,500, 114,427, 113,785, and 313,773 113,785 shares were issued under the ESPP in 2024, 2023, 2022, and 2021, 2022, respectively. Total proceeds to the Company for the issuance of these shares was $3.2 million, $3.1 million, $3.0 million, and $2.6 $3.0 million, for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively. As of December 31, 2023 December 31, 2024, the Company had approximately 3.3 million 3.2 million shares of its common stock available for issuance under the ESPP. The Company records compensation expense associated with the ESPP based on the estimated fair value of the ESPP grants as of the beginning of the offering period, and the expense is recognized within general and administrative expense and exploration expense over the six-month offering period. Total compensation expense recorded for the ESPP for the years ended December 31, 2023 December 31, 2024, 2023, and 2022, and 2021, was $1.0 million, $1.1 million, $1.2 million, and $1.4 $1.2 million, respectively.

The fair value of ESPP grants is measured at the grant date using the Black-Scholes option-pricing model. Expected volatility is calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six-month vesting period.

The fair value of ESPP shares issued during the periods reported above were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022

Risk free interest rate	Risk free interest rate	5.1 %	1.2 %	0.8 %	Risk free interest rate	5.3 %	5.1 %	1.2 %
Dividend yield	Dividend yield	1.8 %	0.1 %	0.3 %	Dividend yield	1.8 %	1.8 %	0.1 %
Volatility factor of the expected market price of the Company's common stock	Volatility factor of the expected market price of the Company's common stock	53.6 %	69.1 %	106.1 %	Volatility factor of the expected market price of the Company's common stock	35.2 %	53.6 %	69.1 %
Expected life (in years)	Expected life (in years)	0.5		0.5	Expected life (in years)	0.5	0.5	

401(k) Plan

The Company has a defined contribution plan ("401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute a maximum of 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches either 100 percent or 150 percent of each employee's contributions, depending on pension plan eligibility, up to six percent of the employee's base salary and short-term incentive bonus, and may make additional contributions at its discretion. Please refer Refer to *Note 11 12 – Pension Benefits* for additional discussion of pension benefits. The Company's matching contributions to the 401(k) Plan were $6.4 million, $5.7 million, $5.5 million, and $3.9 $5.5 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively.

Note 11 – Segment Reporting

The Company's operations are all related to the exploration, development, and production of oil, gas, and NGLs in the United States, from which the Company derives all of its revenue. The nature of the production process, the types of purchasers, and the regulatory environment under which the Company operates are consistent across the Company. Additionally, for financial reporting purposes related to oil and gas extraction activities, the United States is considered to be one geographic area. As a result of these factors, the Company has one reportable segment: the oil, gas, and NGL exploration and production segment ("E&P Segment"). The E&P Segment constitutes all of the consolidated entity and the accompanying consolidated financial statements and the notes to the accompanying consolidated financial statements are representative of such amounts for the E&P Segment. The accounting policies of the E&P Segment are the same as those described in *Note 1 – Summary of Significant Accounting Policies.*

The Company's Chief Operating Decision Maker ("CODM") is the President and Chief Executive Officer. The CODM uses net income as presented on the accompanying statements of operations to measure E&P Segment profit or loss, and to evaluate income generated from E&P Segment assets in deciding whether to reinvest profits into operational activities or to use profits for other purposes, such as debt reduction, acquisitions, or the Company's Stock Repurchase Program. Additionally, net income is used in assessing budget versus actual results and in benchmarking to the Company's competitors.

Segment Revenue, Significant Expenses, and Net Income

	For the Years Ended December 31,		
	2024	**2023**	**2022**
	(in thousands)		
Total operating revenues and other income	$ 2,690,259	$ 2,373,886	$ 3,358,647
Less:			
Lease operating expense	318,987	284,790	266,527
Transportation costs	167,121	136,237	150,049
Production taxes	115,973	105,134	162,629
Ad valorem tax expense	34,890	37,382	41,707
Depletion, depreciation, and amortization	809,305	690,481	603,780
Exploration	64,121	59,480	54,943
General and administrative	138,344	121,063	114,558
Net derivative (gain) loss	(49,958)	(68,154)	374,012
Other operating expense, net	15,781	20,567	10,961
Interest expense	140,659	91,630	120,346
Interest income	(31,903)	(19,854)	(5,774)
Loss on extinguishment of debt	483	—	67,605
Other non-operating income	233	928	1,534
Income tax expense	195,930	96,322	283,818
E&P Segment net income	$ 770,293	$ 817,880	$ 1,111,952

Note: There are no reconciling items between net income presented on the accompanying statements of operations and E&P Segment net income.

Note 12 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering employees who met age and service requirements and began employment with the Company prior to January 1, 2016 (“Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (“Nonqualified Pension Plan” and together with the Qualified Pension Plan, “Pension Plans”). The Company froze the Pension Plans to new participants, effective January 1, 2016. Employees participating in the Pension Plans prior to the plans being frozen continue to earn benefits.

Obligations and Funded Status for the Pension Plans

The Company recognizes the funded status (i.e. (*i.e.*, the difference between the fair value of plan assets and the projected benefit obligation) of the Company’s Pension Plans in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment within the other comprehensive income, net of tax, line item in the accompanying consolidated statements of comprehensive income. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated

benefit obligation uses the same factors as the projected benefit obligation, but excludes the effects of assumed future salary increases.

The Company’s measurement date for plan assets and obligations is December 31.

	For the Years Ended December 31,	
	2023	**2022**
	2024	**2023**
	(in thousands)	
	(in thousands)	
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year		
Projected benefit obligation at beginning of year		
Projected benefit obligation at beginning of year		
Service cost		
Interest cost		
Actuarial (gain) loss		
Benefits paid		
Projected benefit obligation at end of year		
Projected benefit obligation at end of year		
Settlements		
Settlements		
Settlements		
Projected benefit obligation at end of year		
Change in plan assets:		
Change in plan assets:		
Change in plan assets:		
Fair value of plan assets at beginning of year		
Fair value of plan assets at beginning of year		
Fair value of plan assets at beginning of year		
Actual return on plan assets		
Employer contribution		
Benefits paid		
Fair value of plan assets at end of year		
Fair value of plan assets at end of year		
Settlements		
Settlements		
Settlements		
Fair value of plan assets at end of year		
Funded status at end of year		

The Company’s underfunded status for the Pension Plans as of December 31, 2023 December 31, 2024, and 2022, 2023, was $21.6 $13.1 million and $28.7 $21.6 million, respectively, and is recognized in the accompanying balance sheets within the other noncurrent liabilities line item. There are no plan assets in the Nonqualified Pension Plan.

Accumulated Benefit Obligation in Excess of Plan Assets for the Pension Plans

	As of December 31,	
	2023	2022
	2024	2023
	(in thousands)	
	(in thousands)	
	(in thousands)	
Projected benefit obligation		
Accumulated benefit obligation		
Accumulated benefit obligation		
Accumulated benefit obligation		
Less: fair value of plan assets		
Underfunded accumulated benefit obligation		

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate of return on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of the unrecognized net gain or loss resulting from actual experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for the year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation and the market-related value of plan assets, then the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

The pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in the accumulated other comprehensive loss line item within the accompanying balance sheets as of December 31, 2023 December 31, 2024, and 2022, 2023, totaled $3.3 $1.5 million and $5.1 $3.3 million, respectively, and related to unrecognized actuarial losses.

The pension liability adjustments recognized in other comprehensive income during 2024, 2023, 2022, and 2021, 2022, were as follows:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
		(in thousands)	
		(in thousands)	
		(in thousands)	
Net actuarial gain (loss)			
Amortization of prior service cost			
Net actuarial gain			
Amortization of net actuarial loss			
Amortization of net actuarial loss			
Amortization of net actuarial loss			
Settlements			
Total pension liability adjustment, pre-tax			
Tax expense			
Total pension liability adjustment, net			

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
		(in thousands)	
		(in thousands)	
		(in thousands)	
Components of net periodic benefit cost:			
Service cost			
Service cost			
Service cost			
Interest cost			
Expected return on plan assets that reduces periodic pension benefit cost			

Amortization of prior service cost
Amortization of net actuarial loss
Amortization of net actuarial loss
Amortization of net actuarial loss
Net periodic benefit cost
Settlements
Total net benefit cost

Pension Plan Assumptions

The weighted-average assumptions used to measure the Company's projected benefit obligation are as follows:

		As of December 31,				
		2023		2022		
		2024		2023		
Projected benefit obligation:						
Discount rate						
Discount rate						
Discount rate		5.0%	5.2%	5.6%		5.0%
Rate of compensation increase	Rate of compensation increase	3.5%	3.5%	Rate of compensation increase	3.5%	3.5%

The weighted-average assumptions used to measure the Company's net periodic benefit cost are as follows:

		For the Years Ended December 31,						
		2023		2022		2021		
		2024		2023		2022		
Net periodic benefit cost:								
Discount rate								
Discount rate								
Discount rate		5.2%	3.1%	2.9%		5.1%	5.2%	3.1%
Expected return on plan assets (1)	Expected return on plan assets (1)	6.3%	3.6%	4.4%	Expected return on plan assets (1)	6.5%	6.3%	3.6%
Rate of compensation increase	Rate of compensation increase	3.5%	4.8%	4.4%	Rate of compensation increase	3.5%	3.5%	4.8%

(1) There is no assumed expected return on plan assets for the Nonqualified Pension Plan because there are no plan assets in the Nonqualified Pension Plan.

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy prohibits the direct investment of plan assets in the Company's securities. The Qualified Pension Plan's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting of expected returns for given levels of risk are applied.

The Qualified Pension Plan's investment portfolio contains a diversified blend of investments, which may reflect varying rates of return. The investments are further diversified within each asset classification. This portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations.

The weighted-average asset allocation of the Qualified Pension Plan is as follows:

		Target		Target		As of December 31,			Target		As of December 31,	
Asset Category	Asset Category	2024		2023		2022		Asset Category	2025		2024		2023	
Equity securities	Equity securities	49.0	%	43.0	%	47.1	%	Equity securities	30.0	%	41.0	%	43.0	%
Fixed income securities	Fixed income securities	26.0	%	25.5	%	21.0	%	Fixed income securities	50.0	%	40.3	%	25.5	%
Other securities	Other securities	25.0	%	31.5	%	31.9	%	Other securities	20.0	%	18.7	%	31.5	%
Total	Total	100.0	%	100.0	%	100.0	%	Total	100.0	%	100.0	%	100.0	%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in the plan. The assumption of the expected long-term rate of return on plan assets of the Qualified Pension Plan is based upon the target asset allocation and is determined using forward-looking assumptions in the context of historical returns and volatilities for each asset class, as well as correlations among asset classes. The Company evaluates the expected rate of return on plan assets assumption on an annual basis.

Pension Plan Assets

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2023, and 2022, utilizing the fair value hierarchy discussed in *Note 8 – Fair Value Measurements* are as follows:

	Actual Asset Allocation (1)	Actual Asset Allocation (1)	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs	Actual Asset Allocation (1)	Total	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
				Fair Value Measurements Using:							
			(in thousands)								
			(in thousands)								
			(in thousands)								
As of December 31, 2024											
Equity securities:											
Equity securities:											
Equity securities:											
Domestic (2)											
Domestic (2)											
Domestic (2)											
International (3)											
Total equity securities											
Fixed income securities:											
Core fixed income (4)											
Core fixed income (4)											
Core fixed income (4)											
Total fixed income securities											
Total fixed income securities											
Total fixed income securities											
Other securities:											
Real estate (5)											
Real estate (5)											
Real estate (5)											
Collective investment trusts (6)											
Hedge fund (7)											
Total other securities											
Total investments											
As of December 31, 2023											
As of December 31, 2023											
As of December 31, 2023											
Equity securities:											
Equity securities:											
Equity securities:											
Domestic (2)											
Domestic (2)											
Domestic (2)											
International (3)											
Total equity securities											
Fixed income securities:											
Core fixed income (4)											
Core fixed income (4)											
Core fixed income (4)											
Floating rate corporate loans (5)											
Total fixed income securities											
Total fixed income securities											
Total fixed income securities											

Other securities:
Real estate (6)
Real estate (6)
Real estate (6)
Collective investment trusts (7)
Hedge fund (8)
Real estate (5)
Real estate (5)
Real estate (5)
Collective investment trusts (6)
Hedge fund (7)
Total other securities
Total investments
As of December 31, 2022
As of December 31, 2022
As of December 31, 2022
Equity securities:
Equity securities:
Equity securities:
Domestic (2)
Domestic (2)
Domestic (2)
International (3)
Total equity securities
Fixed income securities:
Core fixed income (4)
Core fixed income (4)
Core fixed income (4)
Floating rate corporate loans (5)
Total fixed income securities
Other securities:
Real estate (6)
Real estate (6)
Real estate (6)
Collective investment trusts (7)
Hedge fund (8)
Total other securities
Total investments

(1) Percentages may not calculate due to rounding.

(2) Level 1 equity securities consist of United States large and small capitalization companies, which are actively traded securities that can be sold on demand. Level 2 equity securities are investments in a collective investment fund funds that is are valued at net asset value based on the value of the underlying investments and total units outstanding on a daily basis. The objective of these funds is to approximate the S&P 500 by investing in one or more collective investment funds.

(3) International equity securities consist of a well-diversified portfolio of holdings of mostly large issuers organized in developed countries with liquid markets, commingled with investments in equity securities of issuers located in emerging markets that are believed to have strong sustainable financial productivity at attractive valuations.

(4) The objective of core fixed income funds is to achieve value added from sector or issue selection by constructing a portfolio to approximate the investment results of the Barclay's Capital Aggregate Bond Index with a modest amount of variability in duration around the index.

(5) Investments consist of floating rate bank loans. The interest rates on these loans are typically reset on a periodic basis to account for changes in the level of interest rates.

(6) The investment objective of direct real estate is to provide current income with the potential for long-term capital appreciation. Ownership in real estate entails a long-term time horizon, periodic valuations, and potentially low liquidity.

(7) (6) Collective investment trusts invest in short-term investments and are valued at the net asset value of the collective investment trust. The net asset value, as provided by the trustee, is used as a practical expedient to estimate fair value. The net asset value is based on the fair value of the underlying investments held by the fund less its liabilities.

(8) (7) The hedge fund portfolio includes investments in actively traded global mutual funds that focus on alternative investments and a hedge fund of funds that invests both long and short using a variety of investment strategies.

The following is a summary of the changes in Level 3 plan assets (in thousands):

Balance at January 1, 2022	$	6,195
Purchases		400
Realized gain on assets		259
Unrealized loss on assets		(57)
Disposition		—
Balance at December 31, 2022 January 1, 2023	$	6,797
Purchases		—
Realized gain on assets		364
Unrealized loss on assets		(448)
Disposition		—
Balance at December 31, 2023	$	6,713
Purchases		—
Realized gain on assets		282
Unrealized loss on assets		(110)
Disposition		(1,401)
Balance at December 31, 2024	$	5,484

Contributions

The Company contributed $10.5 million, $10.0 million, $6.0 million, and $6.6 $6.0 million to the Pension Plans for during the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively. The Company expects to make a $10.6 an $8.2 million contribution to the Pension Plans in 2024. 2025.

Benefit Payments

The Pension Plans made actual benefit payments of $2.7 million, $4.9 million, and $2.0 million and $6.3 million for during the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively. Expected benefit payments over the next 10 years are as follows:

For the Years Ending December 31,	For the Years Ending December 31,	Amount	For the Years Ending December 31,	Amount
				(in thousands)
2024				
2025				
2026				
2027				
2028				
2029 through 2033				
2029				
2030 through 2034				

Note 12 13 – Leases

As of December 31, 2023 December 31, 2024, and 2022, 2023, the Company had operating leases for asset classes that include office space, office equipment, drilling rigs, completion crews, midstream agreements, vehicles, railcars, and equipment rentals used in field operations. For operating leases recorded on the accompanying balance sheets, the remaining lease terms range from less than one year to approximately nine eight years. Certain leases contain optional extension periods that allow for terms to be extended for up to an additional 10 years, years; however, in order to maintain financial and operational flexibility, there are no available options to extend that the Company is reasonably certain it will exercise. An early termination option exists for certain leases, some of which allow the Company to terminate a lease within one year, year; however, there are no leases in which material early termination options are reasonably certain to be exercised by the Company. As of December 31, 2023 December 31, 2024, and 2022, 2023, the Company did not have any agreements in place that were classified as finance leases under Topic 842. As of December 31, 2023 December 31, 2024, and through the filing of this report, the Company has no material lease arrangements which are scheduled to commence in the future. Please refer Refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on the Company's policies for lease determination and classification.

The following table reflects the components of the Company's total lease costs, whether capitalized or expensed, related to operating leases, including short-term leases, and variable lease payments made costs for both short-term and long-term leases for the years ended December 31, 2023,

December 31, 2024, 2023, and 2022. This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.

	For the Years Ended December 31,	For the Years Ended December 31,		For the Years Ended December 31,
	2023	2022		
	2024	2023	2022	
	(in thousands)			
	(in thousands)			
	(in thousands)			
Operating lease cost				
Short-term lease cost (1)				
Variable lease cost (2)				
Total lease cost				

(1) Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than one year. This amount includes drilling and completion activities, and field equipment rentals, most of which are contracted for 12 months or less. It is expected that this amount will fluctuate primarily with the number of drilling rigs and completion crews the Company is operating under short-term agreements.

(2) Variable lease payments relate to the actual volumes delivered under certain midstream agreements, actual usage associated with drilling rigs, completion crews, and vehicles, and variable utility costs associated with the Company's leased office space. Fluctuations in variable lease payments are primarily driven by actual volumes delivered and the number of drilling rigs and completion crews operating.

Cash paid for amounts included in the measurement of lease liabilities for the years ended December 31, 2023, and 2022, were as follows:

	For the Years Ended December 31,	For the Years Ended December 31,		For the Years Ended December 31,
	2023	2022		
	2024	2023	2022	
	(in thousands)			
	(in thousands)			
	(in thousands)			
Operating cash flows related to operating leases				
Investing cash flows related to operating leases				

Maturities for the Company's operating lease liabilities included on the accompanying balance sheets as of December 31, 2023 December 31, 2024, were as follows:

	As of December 31, 2023	As of December 31, 2024	(in thousands)
2024			
2025			
2026			
2027			
2028			
2029			
Thereafter			
Total Lease payments			
Less: Imputed interest (1)			
Total			

(1) The weighted-average discount rate used to determine the operating lease liability as of December 31, 2023 December 31, 2024, was 6.2 5.5 percent.

The following table presents supplemental accompanying balance sheet information for operating leases as of December 31, 2023, and 2022: leases:

	As of December 31,	
	2023	2022

	2024	2023
	(in thousands, except discount rate and lease term)	
	(in thousands, except discount rate and lease term)	
	(in thousands, except discount rate and lease term)	
Balance sheet classifications of operating leases:		
Other noncurrent assets		
Other noncurrent assets		
Other noncurrent assets		
Other current liabilities		
Other noncurrent liabilities		
ROU assets obtained in exchange for operating lease liabilities		
ROU assets obtained in exchange for operating lease liabilities		
ROU assets obtained in exchange for operating lease liabilities		

Weighted-average discount rate	Weighted-average discount rate	6.2%	5.8%	Weighted-average discount rate	5.5%	6.2%
Weighted-average remaining lease term (years)	Weighted-average remaining lease term (years)	4	5	Weighted-average remaining lease term (years)	4	4

Note 13 14 – Accounts Receivable and Accounts Payable and Accrued Expenses

The components of accounts receivable are as follows:

	As of December 31,	
	2023	2022
	2024	2023
	(in thousands)	
	(in thousands)	
	(in thousands)	
Oil, gas, and NGL production revenue		
Amounts due from joint interest owners		
Other		
Other		
Other		
Total accounts receivable		

The components of accounts payable and accrued expenses are as follows:

	As of December 31,	
	2023	2022
	2024	2023
	(in thousands)	
	(in thousands)	
	(in thousands)	
Drilling and lease operating cost accruals		
Trade accounts payable		
Revenue and severance tax payable		
Property taxes		
Compensation		
Net derivative settlements		
Interest		
Dividends payable		

Other
Other
Other
Total accounts payable and accrued expenses

Note: Prior periods have been adjusted to conform to the current period presentation.

Note 14 15 – Asset Retirement Obligations

Please refer Refer to *Asset Retirement Obligations* in *Note 1 – Summary of Significant Accounting Policies* for a discussion of the initial and subsequent measurements of asset retirement obligation liabilities and the significant assumptions used in the estimates.

The following is a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2023, and 2022: liability:

	As of December 31,	
	2023	2022
	2024	2023
	(in thousands)	
	(in thousands)	
	(in thousands)	
Beginning asset retirement obligations		
Liabilities incurred (1)		
Liabilities settled (2)		
Accretion expense		
Revision to estimated cash flows		
Ending asset retirement obligations (3)		

(1) Reflects liabilities incurred through drilling activities and acquisitions of drilled wells.

(2) Reflects liabilities settled through plugging and abandonment activities and divestitures of properties.

(3) Balances as of December 31, 2023 December 31, 2024, and 2022, 2023, included $4.4 million $4.0 million and $7.1 million $4.4 million, respectively, related to the Company's current asset retirement obligation liability, which is recorded in the accounts payable and accrued expenses line item on the accompanying balance sheets.

Note 15 16 – Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2023, 2022, and 2021. the periods presented. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in thousands)		
	(in thousands)		
	(in thousands)		
Beginning balance			
Additions to capitalized exploratory well costs pending the determination of net proved reserves			
Reclassifications based on the determination of net proved reserves			
Reclassifications based on the determination of net proved reserves			
Reclassifications based on the determination of net proved reserves			
Capitalized exploratory well costs charged to expense (1)			
Ending balance			

(1) For the year ended December 31, 2024, amount relates to one well deemed non-commercial. For the year ended December 31, 2023, amount relates to one well that experienced technical issues during the drilling phase. For the year ended December 31, 2022, amount relates to unsuccessful exploration activity outside of the Company's core areas of operation.

As of December 31, 2023 December 31, 2024, there were no material exploratory well costs that were capitalized for more than one year.

Note 16 17 – Acquisitions

2024 Acquisition Activity

Uinta Basin Asset Acquisition. On June 27, 2024, the Company entered into a Purchase and Sale Agreement ("XCL Acquisition Agreement") with XCL AssetCo, LLC, XCL Marketing, LLC, Wasatch Water Logistics, LLC, XCL Resources, LLC, and XCL SandCo, LLC, (collectively referred to as the "XCL Sellers" or "XCL Resources") and, for the limited purposes described therein, Northern Oil and Gas, Inc. ("NOG"). Pursuant to the XCL Acquisition Agreement, the Company agreed to purchase all of the rights, titles and interests in primarily proved oil and gas assets, and related supporting facilities in the Uinta Basin owned by the XCL Sellers ("XCL Assets"). Concurrently with the execution of the XCL Acquisition Agreement, the Company entered into an Acquisition and Cooperation Agreement ("Cooperation Agreement") with NOG, pursuant to which the Company and NOG agreed to cooperate in connection with the XCL Acquisition Agreement and NOG agreed to acquire an undivided 20 percent interest in the assets acquired pursuant to the XCL Acquisition Agreement. Upon execution of the XCL Acquisition Agreement, the Company deposited with an escrow agent a cash deposit of $102.0 million ("Cash Deposit"). Pursuant to the terms of the XCL Acquisition Agreement, the Company had the option to acquire certain additional assets adjacent to the XCL Assets ("Altamont Option Assets") from the XCL Sellers for a purchase price equal to the XCL Sellers' cost to acquire the Altamont Option Assets plus the XCL Sellers' related out of pocket expenses. On August 5, 2024, the Company exercised the option to acquire the Altamont Option Assets.

On October 1, 2024 ("Closing Date"), immediately prior to the closing of the transactions contemplated by the XCL Acquisition Agreement, and as permitted by the XCL Acquisition Agreement and Cooperation Agreement, the Company assigned an undivided 20 percent interest in the XCL Acquisition Agreement to NOG and caused the XCL Sellers to directly assign an undivided 20 percent interest in both the XCL Assets and the Altamont Option Assets to NOG. Accordingly, on the Closing Date, the Company completed the acquisition of an undivided 80 percent interest in both the XCL Assets and the Altamont Option Assets with an effective date of May 1, 2024 ("Uinta Basin Acquisition"). The Company's undivided 80 percent interest in the assets acquired in the Uinta Basin Acquisition consists of approximately 63,300 net acres.

On the Closing Date, the unadjusted purchase price, net to the Company's 80 percent undivided interest in the Uinta Basin Acquisition, was approximately $2.1 billion. The Company paid approximately $1.9 billion in cash to the XCL Sellers, using a portion of the net proceeds from the issuance of the 2029 Senior Notes and 2032 Senior Notes discussed in *Note 5 – Long-Term Debt*, cash on hand, and borrowings under the Company's revolving credit facility. Additionally, the $102.0 million Cash Deposit was applied toward the unadjusted purchase price and a majority of the Cash Deposit was disbursed to the XCL Sellers on the Closing Date. The beneficial ownership of the remaining portion of the Cash Deposit transferred to the XCL Sellers on the Closing Date and will remain in escrow pending the completion of post-closing purchase price adjustments, which are expected to occur in the first quarter of 2025.

In accordance with GAAP, this transaction was considered to be an asset acquisition as substantially all the gross assets acquired were concentrated in a group of similar identifiable assets. Therefore, the properties were recorded based on the total consideration paid after purchase price adjustments and the transaction costs were capitalized as a component of the cost of the assets acquired. The adjusted purchase price was allocated to the assets and liabilities acquired based on their estimated fair value as of the acquisition date using certain assumptions including: (i) estimated net proved and unproved reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) risk adjusted future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs required significant judgment by management at the time of the valuation.

The adjusted purchase price was $2.0 billion and was allocated to the assets acquired and liabilities assumed based on the relative fair values on the closing date as follows: (i) $1.6 billion to proved oil and gas properties, (ii) $495.2 million to unproved oil and gas properties, (iii) $16.3 million to both operating lease right-of-use assets and operating liabilities, (iv) $58.1 million to revenue and royalties payable and other liabilities, net, and (v) $15.1 million to asset retirement obligations.

The Uinta Basin Acquisition is subject to normal post-closing adjustments expected to occur in the first quarter of 2025.

2023 Acquisition Activity

On June 30, 2023, the Company acquired approximately 20,000 net acres of oil and gas properties in Dawson and northern Martin counties, Texas. Under authoritative accounting guidance, In accordance with GAAP, this transaction was considered to be an asset acquisition. Therefore, the properties were recorded based on the total consideration paid after purchase price adjustments and the transaction costs were capitalized as a component of the cost of the assets acquired. During the third quarter of 2023, the Company acquired additional working interests in certain wells. wells located in the Midland Basin. Total consideration paid for these transactions, after purchase price adjustments, was $109.9 million. $109.9 million.

Additionally, during the year ended December 31, 2023, the Company completed a non-monetary asset exchange of proved properties in Upton County, Texas. This exchange was recorded at carryover basis with no gain or loss recognized.

Supplemental Oil and Gas Information (unaudited)

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2023	**2022**	**2021**
	2024	**2023**	**2022**
	(in thousands)		
	(in thousands)		
	(in thousands)		
Development costs (1)			
Exploration costs			
Acquisitions			
Proved properties			
Proved properties			
Proved properties			

Unproved properties (2)	
Total, including asset retirement obligations (3)(4)	

(1) Includes facility costs of $42.3 million, $24.1 million, $30.0 million, and $18.2 $30.0 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively.

(2) Includes amounts related to leasing activity and acquiring surface rights outside of acquisitions of proved and unproved properties totaling $2.9 million, $18.1 million, $4.2 million, and $5.8 $4.2 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively.

(3) Includes amounts related to estimated asset retirement obligations of $47.9 million, $6.0 million, $15.1 million, and $12.8 $15.1 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively.

(4) Includes capitalized interest of $25.5 million, $20.4 million, $17.6 million, and $15.0 $17.6 million for the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and gas producing activities and SEC rules for oil and gas reporting of reserve estimation and disclosure.

Proved reserves are the estimated quantities of oil, gas, and NGLs which, that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. All of the Company’s estimated net proved reserves are located in the United States.

The tables below present a summary of changes in the Company’s estimated net proved reserves for each of the years ended December 31, 2023 December 31, 2024, 2022, 2023, and 2021, 2022. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the Company’s total calculated proved reserve PV-10 for each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

	For the Year Ended December 31, 2024			
	Oil	**Gas**	**NGLs**	**Total**
	(MMBbl)	**(Bcf)**	**(MMBbl)**	**(MMBOE)**
Total net proved reserves:				
Beginning of year	230.1	1,532.0	119.5	604.9
Revisions of previous estimates (1)	3.5	30.7	14.1	22.7
Discoveries and extensions	7.2	19.4	0.7	11.1
Sales of reserves	(0.7)	(3.3)	—	(1.2)
Purchases of minerals in place (2)	85.3	107.3	—	103.2
Production	(29.3)	(137.0)	(10.2)	(62.4)
End of year	296.0	1,549.1	124.1	678.3
Net proved developed reserves:				
Beginning of year	118.5	948.5	64.7	341.2
End of year	160.3	1,031.3	71.8	404.0
Net proved undeveloped reserves:				
Beginning of year	111.6	583.5	54.8	263.6
End of year	135.7	517.8	52.4	274.3

Note: Amounts may not calculate due to rounding.

(1) Revisions of previous estimates consist of:

- 74.7 MMBOE of infill reserves;
- 30.5 MMBOE of certain net proved undeveloped reserves cases that are no longer expected to be developed within the five-year period from initial booking as a result of the reallocation of capital to include our Uinta Basin assets, and certain lease obligations;
- 13.4 MMBOE of negative price revisions resulting primarily from decreases in gas prices; and
- 8.0 MMBOE of negative performance revisions related to well performance.

(2) Purchases of minerals in place consist of 103.2 MMBOE acquired as part of the Uinta Basin Acquisition. Refer to *Note 17 – Acquisitions* for additional information.

Refer to *Areas of Operation* in Part I, Items 1 and 2 of this report, and to *Oil and Gas Reserve Quantities* in *Critical Accounting Estimates* in Part II, Item 7 of this report for additional information.

For the Year Ended December 31, 2023

	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	205.8	1,402.9	97.8	537.4
Revisions of previous estimates (1)	38.7	194.2	20.8	91.9
Discoveries and extensions	8.9	69.1	10.5	30.9
Sales of reserves	(3.2)	(13.1)	—	(5.4)
Purchases of minerals in place	3.6	11.2	—	5.5
Production	(23.8)	(132.4)	(9.7)	(55.5)
End of year	230.1	1,532.0	119.5	604.9
Net proved developed reserves:				
Beginning of year	110.4	902.1	57.1	317.8
End of year	118.5	948.5	64.7	341.2
Net proved undeveloped reserves:				
Beginning of year	95.4	500.8	40.7	219.6
End of year	111.6	583.5	54.8	263.6

Note: Amounts may not calculate due to rounding.

(1) Revisions of previous estimates consist of:

- 113.9 MMBOE of infill reserves;
- 65.3 MMBOE of positive performance revisions resulting from changes to decline curve estimates based on reservoir engineering analysis;
- 28.0 MMBOE of negative performance revisions related to well performance;
- 30.8 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company’s future development plans, and due to certain lease obligations; and
- 28.4 MMBOE of negative price revisions resulting primarily from decreases in gas and NGL prices.

Please refer to *Areas of Operation* in Part I, Items 1 and 2 of this report, and to *Oil and Gas Reserve Quantities* in *Critical Accounting Estimates* in Part II, Item 7 of this report for additional information.

	For the Year Ended December 31, 2022			
	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	199.5	1,243.5	85.2	492.0
Revisions of previous estimates (1)	23.7	248.2	16.7	81.7
Discoveries and extensions	6.6	37.2	3.9	16.7
Sales of reserves	—	—	—	—
Purchases of minerals in place	—	—	—	—
Production	(24.0)	(125.9)	(8.0)	(53.0)
End of year	205.8	1,402.9	97.8	537.4
Net proved developed reserves:				
Beginning of year	110.7	833.0	50.7	300.2
End of year	110.4	902.1	57.1	317.8
Net proved undeveloped reserves:				
Beginning of year	88.8	410.4	34.5	191.8
End of year	95.4	500.8	40.7	219.6

Note: Amounts may not calculate due to rounding.

(1) Revisions of previous estimates consist of:

- 103.2 MMBOE of infill reserves;
- 9.5 MMBOE of positive price revisions;
- 19.9 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company’s future development plans; and
- 11.1 MMBOE of negative performance revisions.

	For the Year Ended December 31, 2021			
	Oil	Gas	NGLs	Total
	(MMBbl)	(Bcf)	(MMBbl)	(MMBOE)
Total net proved reserves:				
Beginning of year	172.7	1,052.0	56.6	404.6
Revisions of previous estimates (1)	35.7	158.9	12.2	74.4
Discoveries and extensions	19.3	141.4	21.9	64.7
Sales of reserves	(0.3)	(0.5)	(0.1)	(0.4)
Purchases of minerals in place	0.1	0.1	—	0.1
Production	(27.9)	(108.4)	(5.4)	(51.4)
End of year	199.5	1,243.5	85.2	492.0
Net proved developed reserves:				
Beginning of year	89.8	643.9	32.1	229.3
End of year	110.7	833.0	50.7	300.2
Net proved undeveloped reserves:				
Beginning of year	82.9	408.1	24.4	175.3
End of year	88.8	410.4	34.5	191.8

Note: Amounts may not calculate due to rounding.

(1) Revisions of previous estimates consist of:

- 74.4 MMBOE of infill reserves;
- 37.2 MMBOE and 3.4 MMBOE of positive price and performance revisions, respectively; and
- 40.6 MMBOE of estimated net proved undeveloped reserves reclassified to unproved reserves categories resulting from revising certain aspects of the Company's future development plans.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of discounted future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the estimated proved reserves in place at the end of the period using year end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities and estimated abandonment costs.

The assumptions used to compute the standardized measure of discounted future net cash flows are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value amount. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure of discounted future net cash flows computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure of discounted future net cash flows:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
Oil (per Bbl)			
Gas (per Mcf)			
NGLs (per Bbl)			

The following summary sets forth the Company's future net cash flows relating to proved oil, gas, and NGL reserves based on the standardized measure of discounted future net cash flows:

	As of December 31,		
	2023	2022	2021
	2024	2023	2022
		(in thousands)	
		(in thousands)	
		(in thousands)	
Future cash inflows			
Future production costs			

Future development costs	
Future income taxes	
Future net cash flows	
10 percent annual discount	
Standardized measure of discounted future net cash flows	

The principal sources of changes in the standardized measure of discounted future net cash flows were:

	For the Years Ended December 31,		
	2023	2022	2021
	2024	2023	2022
	(in thousands)		
	(in thousands)		
	(in thousands)		
Standardized measure of discounted future net cash flows, beginning of year			
Sales of oil, gas, and NGLs produced, net of production costs			
Net changes in prices and production costs			
Extensions and discoveries, net of related costs			
Sales of reserves in place			
Purchase of reserves in place			
Previously estimated development costs incurred during the period			
Changes in estimated future development costs			
Revisions of previous quantity estimates			
Accretion of discount			
Net change in income taxes			
Changes in timing and other			
Standardized measure of discounted future net cash flows, end of year			

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including our Chief Executive Officer (Principal Executive Officer) and our Chief Financial Officer (Principal Financial Officer), as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and our Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes to our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2023 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is 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. The Company's internal control over financial reporting includes those policies and procedures that:

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

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2023 December 31, 2024. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (2013 framework).

Based on management's assessment and those criteria, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2023 December 31, 2024.

The Uinta Basin Acquisition was considered the acquisition of a business as defined by Article 11-01(d) of Regulation S-X. As permitted by the SEC, management's assessment and conclusion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2024, excludes an assessment of the internal controls over the oil and gas properties acquired in the Uinta Basin Acquisition. Due to the recent nature of the acquisition, it was not practical from a timing or resource perspective for management to conduct a thorough assessment of the internal control over financial reporting related to the Uinta Basin Acquisition prior to December 31, 2024. The Uinta Basin Acquisition is included in our 2024 consolidated financial statements and represents approximately 27 percent of the total assets of the consolidated Company as of December 31, 2024, and approximately seven percent of consolidated revenues for the year then ended. Refer to *Note 17 – Acquisitions* in Part II, Item 8 of this report for additional discussion of the Uinta Basin Acquisition.

The Company's independent registered public accounting firm has issued an attestation report on the Company's internal control over financial reporting. That report immediately follows this report.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company and subsidiaries

Opinion on Internal Control Over Financial Reporting

We have audited SM Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2023 December 31, 2024, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, SM Energy Company and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023 December 31, 2024, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls over the oil and natural gas properties the Company acquired on October 1, 2024 in the Uinta Basin (the "Uinta Basin Acquisition"). The Uinta Basin Acquisition was included in the 2024 consolidated financial statements of the Company and represented 27% of total consolidated assets as of December 31, 2024 and 7% of consolidated revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of the Uinta Basin Acquisition.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 December 31, 2024 and 2022, 2023, the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2023 December 31, 2024, and the related notes and our report dated February 22, 2024 February 20, 2025 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Denver, Colorado

February 22, 2024 20, 2025

ITEM 9B. OTHER INFORMATION

As part of its regular, annual evaluation of peer compensation practices, the Compensation Committee of the Board of Directors determined that changes were necessary for the Change of Control Executive Severance Agreement for the Company's Senior Vice Presidents, Executive Vice Presidents, and CEO. The Board of Directors approved these recommended changes, and on February 21, 2024, the Company's Senior Vice Presidents, Executive Vice Presidents, and CEO each executed a new Change of Control Executive Severance Agreement, the template of which is filed as Exhibit 10.16 to this report. None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

These disclosures are not applicable to the Company.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning the Company's Directors, Executive Officers, and corporate governance is incorporated by reference to the information provided under the captions *"Proposal 1 - Election of Directors," "Information about our Executive Officers,"* and *"Corporate Governance"* in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

The information required by this Item concerning compliance with Section 16(a) of the Exchange Act is incorporated by reference to the information provided under the caption *"Security Ownership of Certain Beneficial Owners and Management"* in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 annual meeting of stockholders, to be filed within 120 days from December 31, 2023.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions *"Executive Compensation Tables"* and *"Director Compensation"* in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 2025 annual meeting of stockholders, to be filed within 120 days from December 31, 2023 December 31, 2024.

The Company has adopted insider trading policies and procedures governing the purchase, sale, and/or other dispositions of the registrant's securities by directors, officers, and employees. This policy is filed as Exhibit 19.1 to this report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided in the Company's Definitive Proxy Statement on Schedule 14A for the 2025 annual meeting of stockholders, to be filed within 120 days from December 31, 2024.

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

The Company is not aware of any arrangements that may result in a change in control of the Company.

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption *"Security Ownership of Certain Beneficial Owners and Management"* in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 2025 annual meeting of stockholders, to be filed within 120 days from December 31, 2023 December 31, 2024.

Securities Authorized for Issuance Under Equity Compensation Plans. The Company has equity compensation plans under which options and shares of the Company's common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. The Company's stockholders have approved these plans. Please refer Refer to *Note 10 – Compensation Plans* in Part II, Item 8 of this report for further information about the material terms of the Company's equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under equity compensation plans as of December 31, 2023 December 31, 2024:

(a)	**(a)**	**(b)**	**(c)**	**(a)**	**(b)**	**(c)**

Plan category	Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:								
Equity Incentive Compensation Plan (1)								
Equity Incentive Compensation Plan (1)								
Equity Incentive Compensation Plan (1)								
Restricted stock units (2)								
Restricted stock units (2)								
Restricted stock units (2)								
Performance share units (2) (3)								
Performance share units (2) (3)								
Performance share units (2) (3)								
Total for Equity Incentive Compensation Plan								
Total for Equity Incentive Compensation Plan								
Total for Equity Incentive Compensation Plan								
Employee Stock Purchase Plan (4)								
Equity compensation plans not approved by security holders								
Total for all plans								

(1) In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of the Company or any affiliate of the Company. The Company's Board of Directors approved amendments to the Equity Plan in 2009, 2010, 2013, 2016, and 2018 and each amended plan was approved by stockholders at the respective annual stockholders' meetings. The total number of shares of the Company's common stock underlying awards granted in 2024, 2023, 2022, and 2021 2022 under the Equity Plan were 774,687, 943,979, 832,257, and 726,562, 832,257, respectively.

(2) RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per unit fair value, which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per unit fair value for the outstanding RSUs and PSUs was $31.40 $37.73 and $27.75, $32.83, respectively. Please refer Refer to *Note 10 – Compensation Plans* in Part II, Item 8 of this report for additional discussion.

(3) The number of shares of common stock assumes a multiplier of one. The actual final number of shares of common stock to be issued will range from zero to two times the number of PSUs awarded depending on the three-year performance multiplier.

(4) Under the ESPP, eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation, subject to certain limitations discussed in *Note 10 – Compensation Plans* in Part II, Item 8 of this report. The purchase price of the common stock is 85 percent of the lower of the trading price of the common stock on either the first or last day of the six-month offering period. The ESPP is intended to qualify under Section 423 of the IRC. The total number of shares of the Company's common stock issued in 2024, 2023, 2022, and 2021 2022 under the ESPP were 97,500, 114,427, 113,785, and 313,773, 113,785, respectively.

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

The information required by this Item is incorporated by reference to the information provided under the captions "*Certain Relationships and Related Transactions*" and "*Corporate Governance*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 2025 annual meeting of stockholders, to be filed within 120 days from December 31, 2023 December 31, 2024.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the captions "*Independent Registered Public Accounting Firm*" and "*Audit Committee Pre-approval Policy and Procedures*" in the Company's Definitive Proxy Statement on Schedule 14A for the 2024 2025 annual meeting of stockholders, to be filed within 120 days from December 31, 2023 December 31, 2024.

PART IV

ITEM 15. EXHIBITS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Consolidated Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Certificate of Amendment of Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010, dated May 25, 2023 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on May 30, 2023, and incorporated herein by reference)
3.3	Amended and Restated By-Laws of SM Energy Company, effective as of February 21, 2017 (filed as Exhibit 3.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)
4.1	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.2	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.3	Base Indenture, dated as of May 21, 2015, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.4	Third Supplemental Indenture, dated September 12, 2016 by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on September 12, 2016, and incorporated herein by reference)
4.5	Fourth Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)
4.6 4.6	Fifth Supplemental Indenture, dated as of June 23, 2021, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on June 23, 2021, and incorporated herein by reference)
4. 4.7	7 Indenture, dated as of July 25, 2024, by and between SM Energy Company and U.S. Bank Trust Company, National Association, as trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 25, 2024, and incorporated herein by reference)
* 4.8*	Description of Securities
10.1	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.2	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.3	Seventh Amended and Restated Credit Agreement dated as of August 2, 2022, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022, and incorporated herein by reference)
10.4	First Amendment to Seventh Amended and Restated Credit Agreement, dated as of July 2, 2024, by and among SM Energy Company, a Delaware corporation,

each of the Lenders that is a party thereto; and Wells Fargo Bank, National Association, as administrative agent for the Lenders, the Issuing Banks and the Swingline Lender (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on July 8, 2024, and incorporated herein by reference)

10.4† 10.5	Second Amendment to Seventh Amended and Restated Credit Agreement, dated as of October 1, 2024, by and among SM Energy Company, a Delaware corporation, each of the Lenders that is a party thereto; and Wells Fargo Bank, National Association, as administrative agent for the Lenders, the Issuing Banks and the Swingline Lender (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 2, 2024, and incorporated

	incorporated herein by reference)
10.6	Purchase and Sale Agreement dated as of June 27, 2024 by and among XCL AssetCo, LLC, XCL Marketing, LLC, Wasatch Water Logistics, LLC, XCL Resources, LLC and XCL SandCo, LLC, as Seller, and SM Energy Company, as Purchaser, and solely for the limited purposes as set forth therein, Northern Oil and Gas, Inc. (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 28, 2024, and incorporated herein by reference)
10.7	Acquisition and Cooperation Agreement dated as of June 27, 2024 by and between SM Energy Company and Northern Oil and Gas, Inc. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on June 28, 2024, and incorporated herein by reference)
10.8††	Net Profits Interest Bonus Plan, As Amended by

		Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.5†	10.9†	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 (filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.6†	10.10†	Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.7†	10.11†	Amendment No. 2 to the Pension Plan for Employees of SM Energy Company

amended as of January 1, 2012 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)

10.8† 10.12†	Amendment No. 3 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2016 (filed as Exhibit 10.29 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2015, and incorporated herein by reference)
10.9+ 10.13+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of December 31, 2010 (filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.10† 10.14†	SM Energy Company Non-Qualified Deferred Compensation Plan as of

		March 10, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 24, 2014, and incorporated herein by reference)
10.11†	10.15†	Cash Bonus Plan, As Amended and Restated as of February 1, 2014 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2013, and incorporated herein by reference)
10.12†	10.16†	Section 162(m) Cash Bonus Plan, effective as of May 21, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 28, 2014, and incorporated herein by reference)
10.13†	10.17†	SM Energy Company Employee Stock Purchase Plan, amended and restated effective as of April 5, 2021 (filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 16, 2021, and incorporated herein by reference)

10.14†	10.18†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
10.15*	10.19*†	Summary of Compensation Arrangements for Non-Employee Directors
10.16*†	10.20†	Change of Control Executive Severance Agreement(filed as Exhibit 10.16 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated herein by reference)
10.17†	10.21†	Change of Control Severance Agreement dated December 18, 2022 between Lehman E. Newton, III and SM Energy Company. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 21, 2022, and

		incorporated herein by reference)
10.18†	10.22†	Change of Control Severance Agreement dated December 29, 2022 between David Copeland and SM Energy Company. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 30, 2022, and incorporated herein by reference)
10.19†	10.23†	Non-Competition and Non-Solicitation Agreement dated December 18, 2022 between Lehman E. Newton, III and SM Energy Company (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 21, 2022, and incorporated herein by reference)

10.20† 10.24†	Non-Competition and Non-Solicitation Agreement dated December 29, 2022 between David Copeland and SM Energy Company (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on December 30, 2022, and incorporated herein by reference)
10.21† 10.25†	SM Energy Company Equity Incentive Compensation Plan, amended and restated effective as of May 22, 2018 (filed as Annex A in the registrant’s Definitive Proxy Statement on Schedule 14A, filed on April 12, 2018, and incorporated herein by reference)
10.22*† 10.26†	Form Form of Performance Performance Share Unit Award Agreement as of July July 1, 2023 1, 2023 (filed as Exhibit 10.22 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated herein by reference)
10.23*† 10.27†	Form Form of Restricted Stock Unit Award Agreement as of July 1, 2023(filed as Exhibit 10.23 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated herein by reference)
19.1*	Insider Trading Policy and Procedures
21.1*	Subsidiaries of Registrant
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Ryder Scott Company L.P.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
97.1*† 95.1*	Mine Safety Disclosures
97.1†	Policy Relating to Recovery of Erroneously Awarded Compensation(filed as Exhibit 97.1 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated herein by reference)

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

* Filed with this report.

** Furnished with this report.

† Exhibit constitutes a management contract or compensatory plan or agreement.

†† Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.

+ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. Please refer Refer to Item 15(a) above.

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.

SM ENERGY COMPANY

(Registrant)

Date:	February 22, 2024 20, 2025	By:	/s/ HERBERT S. VOGEL
			Herbert S. Vogel
			President and Chief Executive Officer
			(Principal Executive Officer)

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Herbert S. Vogel and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2023 December 31, 2024, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ HERBERT S. VOGEL	President, Chief Executive Officer, and Director	February 22, 2024 20, 2025
Herbert S. Vogel	(Principal Executive Officer)	
/s/ A. WADE PURSELL	Executive Vice President and Chief Financial Officer	February 22, 2024 20, 2025
A. Wade Pursell	(Principal Financial Officer)	
/s/ PATRICK A. LYTLE	Vice President - Chief Accounting Officer and Controller	February 22, 2024 20, 2025
Patrick A. Lytle	(Principal Accounting Officer)	

Signature	Title	Date
/s/ JULIO M. QUINTANA Julio M. Quintana	Chairman of the Board of Directors	February 22, 2024 20, 2025
/s/ CARLA J. BAILO Carla J. Bailo	Director	February 22, 2024 20, 2025
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 22, 2024 20, 2025
/s/ BARTON R. BROOKMAN Barton R. Brookman	Director	February 20, 2025
/s/ RAMIRO G. PERU Ramiro G. Peru	Director	February 22, 2024 20, 2025
/s/ ANITA M. POWERS Anita M. Powers	Director	February 22, 2024 20, 2025
/s/ ROSE M. ROBESON Rose M. Robeson	Director	February 22, 2024 20, 2025
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 22, 2024 20, 2025
/s/ ASHWIN VENKATRAMAN Ashwin Venkatraman	Director	February 20, 2025

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EXHIBIT 4.7 4.8

DESCRIPTION OF SECURITIES

As of December 31, 2023 December 31, 2024, SM Energy Company has registered one class of securities under Section 12 of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**").

Description of Common Stock

The following description of our Common Stock is a summary and does not purport to be complete. It is subject to, and qualified in its entirety by, reference to our Restated Certificate of Incorporation (the "**Certificate of Incorporation**") and our Amended and Restated By-laws (the "**Bylaws**"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit is a part. We encourage you to read our Certificate of Incorporation, our Bylaws and the applicable provisions of the Delaware General Corporate Law, for additional information.

Authorized Capital Shares

Our authorized capital shares consist of 200,000,000 shares of capital stock, $0.01 par value per share. We have outstanding shares of common stock ("**Common Stock**"). The outstanding shares of our Common Stock are fully paid and non-assessable. This means the full purchase price for the outstanding shares of Common Stock has been paid and the holders of such shares will not be assessed any additional amounts for such shares. Any additional shares of Common Stock that the Company may issue in the future will also be fully paid and non-assessable.

The Certificate of Incorporation provides that authorized but unissued shares of Common Stock are available for future issuance without stockholder approval, subject to various limitations imposed by the New York Stock Exchange ("**NYSE**"). These additional shares of Common Stock may be utilized for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. The existence of authorized but unissued shares of Common Stock could make it more difficult or discourage an attempt to obtain control of the Company by means of a proxy contest, tender offer, merger or otherwise.

Voting Rights

Each share of Common Stock is entitled to one vote on all matters submitted to a vote of the stockholders, including the election of directors. Our Common Stock does not have cumulative voting rights. This means a holder of a single share of Common Stock cannot cast more than one vote for each position to be filled on the Board of Directors. It also means the holders of a majority of the shares of Common Stock entitled to vote in the election of directors can elect all directors standing for election and the holders of the remaining shares will not be able to elect any directors.

Dividend Rights

The holders of Common Stock are entitled to receive ratably such dividends, if any, as may be declared from time to time by the Board of Directors in its discretion out of funds legally available for the payment of dividends. Delaware law allows a corporation to pay dividends only out of surplus, as determined under Delaware law.

Liquidation Rights

Upon the liquidation, dissolution or winding up of the Company, the holders of Common Stock are entitled to receive ratably the net assets of the Company legally available for distribution.

Other Rights and Preferences

Our Common Stock has no sinking fund provision or preemptive, subscription or conversion rights. The holders of Common Stock may act by unanimous written consent.

Listing

Our Common Stock is traded on the NYSE under the trading symbol "SM."

EXHIBIT 10.15 10.19

SUMMARY OF COMPENSATION ARRANGEMENTS FOR NON-EMPLOYEE DIRECTORS

The following is a description of the standard arrangements pursuant to which members of the Board of Directors (a "Director" or the "Board") of SM Energy Company (the "Company") are compensated for their services:

DIRECTOR COMPENSATION

Employee directors do not receive compensation for their service on the Board or any committee of the Board (each a "Committee").

Directors are generally elected by the Company's stockholders at their annual meeting in late May of each year to serve a one-year term through the subsequent year's annual meeting of stockholders. For service during the 2023 2024 - 2024 2025 term, target base compensation for each member of the Board of Directors was set at $270,000 $280,000 annually, and was split between (i) an equity grant comprised of the Company's common stock valued at $180,000 $185,000 at the time of election; and (ii) a cash retainer of $90,000, $95,000, paid in lieu of Board and Committee meeting attendance fees.

With respect to the annual equity grant component of a Director's compensation, the number of shares issued to each Director was determined based on the closing price of the Company's common stock on the date of election to the Board and resulted in the grant of 6,541 3,850 shares to each non-employee Director, which shares were restricted upon issuance until they vested on December 31, 2023 December 31, 2024.

With respect to the cash retainer component of a Director's compensation, Directors may elect to receive shares of the Company's common stock in lieu of, and of a value equal to, the amount of the annual cash retainer. Further, if any non-employee Director attends more than 30 Board and Committee meetings in the aggregate during the one-year term, such Director is entitled to $1,500 per meeting for each meeting in excess of 30. No Director attended more than 30 Board and Committee meetings during the trailing one-year term.

In addition, each Director is reimbursed for expenses incurred in attending Board and Committee meetings and director education programs.

In addition to the base Director compensation structure described above, the non-executive chairman of the Board and the chair of each Committee received compensation in the amounts set forth below in recognition of the additional workload of their respective assignments. With the exception of the non-executive chairman payment, these amounts were paid in cash at the beginning of the annual service period.

- Non-executive Chairman - $125,000 $140,000 (equity compensation paid in the form of 4,543 2,914 shares of the Company's common stock based on the closing price on the date of the Company's annual meeting); these shares were restricted upon issuance until they vested on December 31, 2023 December 31, 2024.
- Audit Committee - $25,000

- Compensation Committee - $20,000
- Environmental, Social and Governance Committee - $15,000

For their 2023 his 2024 - 2024 2025 term of service, Anita Powers and William Sullivan Barton Brookman elected to receive their cash his retainer in the form of shares of the Company's Company's common stock, which resulted in a grant of 3,271 1,977 additional shares of SM Energy common stock. These shares were restricted upon issuance until they vested on December 31, 2023 December 31, 2024. Carla Bailo, Stephen Brand, Ramiro Peru, Anita M. Powers, Julio Quintana, and Rose Robeson and William Sullivan each elected to receive a $90,000 the $95,000 cash payment for their retainer.

Barton Brookman was appointed to the Board on February 16, 2024, and received the same compensation arrangement as the other members of the Board for that term, prorated for his term of service. For his 2023 - 2024 term of service, Mr. Brookman received 1,226 shares based on the closing price of the Company's common stock on February 16, 2024, and elected to receive his prorated $90,000 cash retainer in the form of shares of the Company's common stock, which resulted in the additional grant of 613 shares. These shares were restricted upon issuance until they vested on December 31, 2024.

Dr. Ashwin Venkatraman was appointed to the Board on November 26, 2024, and received the same compensation arrangement as the other members of the Board for that term, prorated for his term of service. For his

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2024 - 2025 term of service, Dr. Venkatraman received 2,027 shares based on the closing price of the Company's common stock on November 26, 2024, and a $46,456 cash payment. These shares were restricted upon issuance until they vested on December 31, 2024.

All shares issued to Directors as compensation for their Board service are issued under SM Energy's Equity Incentive Compensation Plan.

EXHIBIT 10.16 19.1

CHANGE OF CONTROL EXECUTIVE SEVERANCE AGREEMENT SECURITIES TRADING POLICY

(Adopted as of July 27, 2023)

This Change of Control Executive Severance Agreement is entered into effect this [___], 2024 (the Securities Trading Policy (this "**Effective Date Policy**") by and between provides guidelines with respect to transactions in the securities of SM Energy Company a Delaware corporation (the "**Company**"), and the below named employee handling of confidential information about the Company (the "***Executive***"). and the companies with which the Company engages or does business. The Company's Board of Directors has adopted this Policy to promote compliance with applicable securities laws.

RECITALS

A. The This Policy applies to the members of the Company's Board of Directors, of the Company (the "***Board***") has determined that it is in the best interests of the Company to ensure that the Company will have the continued dedication of the Executive notwithstanding the possibility of a Change of Control (as defined in Section 1) all officers and employees of the Company, and to provide the Executive with customary compensation contractors and benefits arrangements upon a Change of Control which ensure that the compensation and benefits expectations consultants of the Executive will be satisfied Company who receive or become aware of material nonpublic information (as described herein). This Policy also applies to family members, other members of a person's household, and which entities controlled by a person covered by this Policy (defined below as "Related Persons"), who receive material nonpublic information. The foregoing persons to whom this Policy applies are competitive referred to herein as "**insiders**." All insiders must comply strictly with those of other companies, and therefore the Board has previously adopted a Change of Control Executive Severance Policy applicable to the Executive. this Policy.

B. This Agreement supersedes and replaces any Change of Control Severance Agreement by and between the Executive and the Company.

C. This Agreement reflects the terms and conditions of the Change of Control Executive Severance Policy.

D. The Company desires reserves the right to continue the employment of the Executive and the Executive desires to continue [his/her] employment with the Company, all upon and subject to the terms and conditions set forth in amend or rescind this Agreement.

NOW, THEREFORE, in consideration of the Executive's continued employment with the Company and the mutual agreements set forth herein, the parties hereto agree as follows:

AGREEMENT

Section 1. Certain Definitions. The following terms shall for purposes of this Agreement have the following respective definitions:

(a) "***Accrued Compensation***" shall mean all compensation amounts earned or accrued by the Executive through the Termination Date (as defined below) but not paid to the Executive as of the Termination Date, including (i) Base Salary (as defined below), (ii) PTO pay (to the extent provided by Company policy, plan, program or practice or applicable law), (iii) bonuses and incentive compensation, and (iv) reimbursement for reasonable and necessary business expenses incurred by the Executive on behalf of the Company during the period ending on the Termination Date. For the avoidance of doubt, if the Termination Date occurs prior to the payment of an award pursuant to the Company's Short Term Incentive Plan but after the completion of the calendar year related to such award, then the amount of such award shall be included as Accrued Compensation.

(b) "***Base Salary***" shall mean the greater of (i) the Executive's annual base salary at the rate in effect on the Termination Date or (ii) the Executive's annual base salary at the rate in effect immediately prior to a Change of Control, and shall include all amounts of [his/her] base salary that are deferred under the qualified and nonqualified employee benefits plans, policies, programs or practices of the Company Policy or any other compensation agreement or arrangement.

(c) "***Cause***" shall mean for purposes portion of termination of employment (i) the conviction of the Executive of a felony involving moral turpitude or (ii) a resolution adopted in good faith by two-thirds of the members of the Board that the Executive (A) intentionally and continually failed to substantially perform [his/her] reasonably assigned duties with the Company (other than a failure resulting from the Executive's incapacity due to physical or mental illness or from the assignment to the Executive of duties that would constitute Good Reason (as defined below)), which failure continued for a period of at least 30 days after a written notice of demand for substantial performance has been delivered by the Company to the Executive, which notice specifies the manner in which the Executive failed to substantially perform, or (B) intentionally engaged in conduct which is demonstrably and materially injurious to the Company; provided, however, that no termination of the Executive's employment shall be for Cause until written notice has been delivered to the Executive which sets forth the conduct under this Section 1(c) of which the Executive is allegedly guilty and specifying the particulars thereof in detail. Neither an act nor a failure to act on the Executive's part shall be considered "intentional" unless the Executive has acted or failed to act with a lack of good faith and with a lack of reasonable belief that the Executive's action or failure to act was in the best interests of the Company. Notwithstanding anything to the contrary contained in this Agreement, no failure to perform by the Executive after a Notice of Termination (as defined below) is given by the Executive to the Company shall constitute Cause for purposes of this Agreement.

(d) "***Change of Control***" shall mean any of the following events:

(i) (A) The acquisition by any individual or entity (a "***Person***") or group of Persons of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Securities Exchange Act of 1934) of more than 50% of either (1) the then value of the outstanding shares of common stock of the Company, or (2) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors.

(B) For purposes of paragraph (A), Persons will not be considered to be acting as a group solely because they purchase or own stock of the same corporation at the same time, or as a result of the same public offering. However, Persons will be considered to be acting as a group if they are owners of a corporation that enters into a merger, consolidation, purchase or acquisition of stock, or similar business transaction with the Company. If a Person, including an entity, owns stock in both corporations that enter into a merger, consolidation, purchase or acquisition of stock, or similar transaction, such shareholder is considered to be acting as a group with other shareholders in a corporation prior to the transaction giving rise to the change and not with respect to the ownership interest in the other corporation. For purposes of determining stock ownership, see (d)(iv), below.

(ii) A majority of members of the Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board prior to the date of the appointment or election; or

(iii) (A) Any one Person, or more than one Person acting as a group (as determined in (d)(iii)(C) below), acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such Person or Persons) assets from the Company that have a total gross fair market value equal to or more than 50 percent of the total gross fair market value of all of the assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, gross fair market value means the value of the assets of the Company, or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets.

(B) A transfer of assets by the Company is not treated as a change in the ownership of such assets if the assets are transferred to –

(1) A shareholder of the Company (immediately before the asset transfer) in exchange for or with respect to its stock;

(2) An entity, 50 percent or more of the total value or voting power of which is owned, directly or indirectly, by the Company;

(3) A Person, or more than one Person acting as a group, that owns, directly or indirectly, 50 percent or more of the total value or voting power of all the outstanding stock of the Company; or

(4) An entity, at least 50 percent of the total value or voting power of which is owned, directly or indirectly, by a Person described in (d)(iii)(B)(3).

For purposes of this paragraph (d)(iii)(B) and except as otherwise provided, a Person's status is determined immediately after the transfer of the assets. For example, a transfer to a corporation in which the Company has no ownership interest before the transaction, but which is a majority-owned subsidiary of the Company after the transaction, is not treated as a change in the ownership of the assets of the Company.

(C) Persons will not be considered to be acting as a group for purposes of this paragraph (d)(iii) solely because they purchase assets of the Company at the same time, or as a result of the same public offering. However, Persons will be considered to be acting as a group if they are owners of a corporation that enters into a merger, consolidation, purchase or acquisition of assets, or similar business transaction with the Company. If a Person, including an entity shareholder, owns stock in both corporations that enter into a merger, consolidation, purchase or acquisition of stock, or similar transaction, such shareholder is considered to be acting as a group with other shareholders in a corporation only to the extent of the ownership in that corporation prior to the transaction giving rise to the change and not with respect to the ownership interest in the other corporation.

(D) For purposes of determining stock ownership, see (d)(iv) below.

(iv) For purposes of determining whether there has been a Change of Control, Code Section 318(a) applies to determine stock ownership. Stock underlying a vested option is considered owned by the individual who holds the vested option (and the stock underlying an unvested option is not considered owned by the individual who holds the unvested option). For purposes of the preceding sentence, however, if a vested option is exercisable for stock that is not substantially vested (as defined by §§1.83-3(b) and (j) of the income tax regulations promulgated by the Internal Revenue Service), the stock underlying the option is not treated as owned by the individual who holds the option.

(e) "***Change of Control Date***" shall mean the first date during the term of this agreement (as specified in Section 2) on which a Change of Control occurs. Notwithstanding anything to the contrary contained in this Agreement, if a Change of Control occurs and if the Executive's employment with the Company is terminated prior to the date on which the Change of Control occurs, and if it is reasonably demonstrated by the Executive that such termination of employment (i) was at the request of a third party who has taken steps reasonably calculated to effect the Change of Control or (ii) otherwise arose in connection with or anticipation of the Change of Control, then for all purposes of this Agreement the "Change of Control Date" shall mean the date immediately prior to the date of such termination of employment.

(f) "***Change of Control Period***" shall mean the period commencing on the Change of Control Date and ending on the date two and one-half years after the Change of Control Date.

(g) "***Code***" shall mean the Internal Revenue Code of 1986, as amended.

(h) "***Disability***" shall mean a physical or mental infirmity which impairs the Executive's ability to substantially perform [his/her] employment duties with the Company on a full-time basis for a period of 120 consecutive business days, and the Executive has not returned to full-time performance of [his/her] employment duties within 30 days after notice by the Company of its intention to terminate employment of the Executive as a result thereof.

(i) "***Good Reason***" shall mean the occurrence after a Change of Control of any of the following events or conditions:

(i) a change in the Executive's status, authority, position, offices, titles, duties or responsibilities (including reporting responsibilities) with the Company which in the Executive's reasonable judgment represents a diminution or adverse change in, or are inconsistent with, such status, authority, position, offices, titles, duties or responsibilities in effect at any time within the 90 days preceding the Change of Control Date or and to adopt different policies and procedures at any time thereafter, excluding for this purpose (A) an isolated, unsubstantial and inadvertent action by the Company not taken in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive and (B) any removal or failure to reappoint or reelect the Executive to any such position or offices in connection with the termination of [his/her] employment for death, Disability or Cause;

(ii) any reduction in the Executive's salary or any failure to pay the Executive any compensation or benefits to which [he/she] is entitled within ten business days after notice thereof;

(iii) the failure by the Company to provide the Executive with compensation and benefits, in the aggregate, at least equal (in terms of benefit levels and/or incentive or reward opportunities) to those provided for under each compensation and employee benefit policy, plan, program and practice in which the Executive was participating at any time within 90 days preceding the Change of Control Date or at any time thereafter;

(iv) the Company's requiring the Executive to be based at any place outside a 25-mile radius from [his/her] current location of employment, except for reasonably required travel for the Company's business which is not materially greater than such travel requirements prior to the Change of Control;

(v) any material breach by the Company of any provision of this Agreement;

(vi) any purported termination by the Company of the Executive's employment other than as expressly permitted by this Agreement; or

(vii) the failure by the Company to obtain an agreement reasonably satisfactory to the Executive from any successor to the Company to assume and agree to perform this Agreement as contemplated by Section 7(b).

Any event or condition described in clauses (i) through (vii) above which occurs prior to a Change of Control but which the Executive reasonably demonstrates (A) resulted from the request of a third party who has taken steps reasonably calculated to effect a Change of Control which actually occurs or (B) otherwise arose in connection with or anticipation of a Change of Control which actually occurs, shall constitute Good Reason for purposes of this Agreement notwithstanding the fact that it occurred prior to the Change of Control. The Executive's right to terminate [his/her] employment for Good Reason shall not be affected by [his/her] incapacity due to a Disability.

(j) "***Notice of Termination***" shall mean a written notice of termination of the Executive's employment which (i) indicates the specific termination provision in this Agreement relied upon for such termination, (ii) to the extent applicable sets forth in reasonable detail the facts and circumstances claimed to provide a basis for such termination under the provision so indicated and (iii) if the Termination Date is other than the date of receipt of such notice, specifies the Termination Date under such notice.

(k) "***Target Percentage***" shall mean the greater of (i) the Executive's Short Term Incentive Plan target percentage in effect on the Termination Date or (ii) the Executive's Short Term Incentive Plan target percentage in effect immediately prior to a Change of Control.

(l) "***Termination Date***" shall mean (i) if the Executive's employment is terminated by the Executive for Good Reason, the date of receipt of the Notice of Termination or any later date of employment termination as specified therein, (ii) if the Executive's employment is terminated by reason of death, the Termination Date shall be the date of death and (iii) in all other cases, the date of employment termination specified in the Notice of Termination; provided, however, that if the Executive's employment is terminated by the Company for Cause or due to a Disability, the date specified in the Notice of Termination shall be at least 30 days from the date the Notice of Termination is given to the Executive, provided that in the case of Disability the Executive shall not have returned to the full-time performance of [his/her] duties during such 30-day period.

Section 2. Term of Agreement. This Agreement shall commence as of the Effective Date and shall continue in effect until December 31, 2024; provided, however, that on December 31, 2024, and on each annual anniversary of such date (such date and each annual anniversary thereof shall be hereinafter referred to as the "***Renewal Date***"), the term of the Agreement shall be automatically extended so as to terminate one year from such Renewal Date, unless at least 60 days prior to the Renewal Date the Company has given written notice to the Executive that the term of the Agreement shall not be so extended, and provided further that notwithstanding any such notice by the Company not to extend, the term of the Agreement shall not expire after the occurrence of a Change of Control until the expiration of the Change of Control Period, as long as the term of the Agreement had not expired prior to the occurrence of the Change of Control.

Section 3. Payments and Benefits Upon Termination of Employment During Change of Control Period. If during the term of this Agreement the Executive shall cease to be employed by the Company within a Change of Control Period, the Executive shall be entitled to the following compensation payments and benefits:

(a) Termination Other than for Cause or Disability or Termination for Good Reason. If the Executive's employment with the Company shall be terminated before the Executive's death either (i) by the Company other than for Cause or Disability or (ii) by the Executive for Good Reason, the Executive shall be entitled to the following:

(i) the Company shall pay the Executive all Accrued Compensation;

(ii) the Company shall pay the Executive a lump sum equal to [Vice Presidents – 2.0; Senior/Executive Vice Presidents – 2.5; CEO – 3.0] *multiplied by* Executive's Base Salary;

(iii) the Company shall pay the Executive a lump sum equal to (A) [Vice Presidents – 2.0; Senior/Executive Vice Presidents – 2.5; CEO – 3.0] *multiplied by* (B) the Executive's Base Salary *multiplied by* (C) the Executive's Target Percentage;

(iv) the Company shall pay the Executive a lump sum equal to (A) the Executive's Short Term Incentive Plan target percentage *multiplied by* (B) the Executive's Base Salary *multiplied by* (C) a fraction,

the numerator of which is the number of days between January 1 and the Termination Date and the denominator of which is 365; and

(v) the Company shall pay the Executive a lump sum equal to 24 *multiplied* by the Company's then monthly contribution for medical, dental, and vision insurance on behalf of the Executive and [his/her] family.

(b) Termination for Cause, Disability or Death or Other than for Good Reason. If the Executive's employment with the Company shall be terminated either (i) by the Company for Cause or Disability, (ii) by reason of the Executive's death, or (iii) by the Executive other than for Good Reason, the Company shall pay to the Executive all Accrued Compensation.

(c) Other Compensation and Benefits. The Executive's entitlement to any other compensation or benefits from or any indemnification by the Company shall be determined in accordance with the Company's employee benefit and other applicable compensation plans, programs, policies and practices, and any applicable indemnification provisions or agreements then in effect. Nothing in this Agreement shall prevent or limit the Executive's continuing or future participation in any plan, program, policy or practice provided by the Company or any of its affiliated companies and for which the Executive may qualify, nor shall anything herein limit or otherwise affect such rights as the Executive may have under any contract or agreement with the Company or any of its affiliated companies. Amounts which are vested benefits or which the Executive is otherwise entitled to receive under any plan, policy, practice or program of or any contract or agreement with the Company or any of its affiliated companies at or subsequent to the Termination Date shall be payable in accordance with such plan, policy, practice or program or contract or agreement except as explicitly modified by this Agreement. If the Executive is entitled to severance pay and benefits pursuant to Section 3(a)(ii) and (iii), such severance pay and benefits shall be reduced to the extent of any other severance or termination pay explicitly designated as such to which the Executive may be entitled under any agreement with the Company or any of its affiliated companies.

(d) Section 409A of the Code. This Agreement is intended in all respects to comply with the provisions of Section 409A of the Code and in particular, those provisions of Section 409A dealing with distributions. This Agreement shall be interpreted and applied in a manner consistent with Section 409A of the Code and any ambiguity shall be resolved in favor of compliance with Section 409A of the Code. time. In the event any payments or benefits pursuant to the other provisions of this Agreement would result in the imposition on the Executive of any additional taxes or interest pursuant to the provisions of Section 409A of the Code and final Treasury Regulations, Internal Revenue Service guidance or other provisions of law, the amount of such payments shall be appropriately and equitably adjusted in order that the Executive may receive the same economic benefits as provided under this Agreement and in compliance with Section 409A of the Code and without the imposition on the Executive of any additional taxes and interest thereunder. Any payments to the Executive under this Agreement which Section 409A(a)(2)(B)(i) of the Code indicates may not be made before the date which is six months after the date of Executive's separation from employment service (the "Section 409A Six-Month Waiting Period") shall not be made during the Section 409A Six-Month Waiting Period but rather shall be delayed and shall be paid upon the expiration of the Section 409A Six-Month Waiting Period. In particular, with respect to severance payments provided for under Section 3(a)(ii) of this Agreement, such severance payments that would otherwise be paid during the Section 409A Six-Month Waiting Period shall be paid in lump sum upon the expiration of the Section 409A Six-Month Waiting Period, together with simple interest on the amount of each deferred payment at the short term applicable federal rate as of the date of termination of employment. For purposes of this Agreement, "termination of employment," "separation from service" or similar language means separation from service by the Executive from the Company for any reason whatsoever within the meaning of Code Section 409A and Treasury Regulation § 1.409A-1(h).

Section 4. Notice of Termination. Following a Change of Control, any purported termination of the Executive's employment by the Company, for Cause or otherwise, or by the Executive for Good Reason, shall be communicated by a Notice of Termination to the other party hereto given in accordance with Section 8(d). For purposes of this Agreement, no such purported termination shall be effective without such Notice of Termination. The failure by the Executive or the Company to set forth in the Notice of Termination any fact or circumstance which contributes to a showing of Good Reason or Cause shall not waive any right of the Executive or the Company hereunder or preclude the Executive or the Company from asserting such fact or circumstance in enforcing the Executive's or the Company's rights hereunder. If the Company determines in good faith that a Disability of the Executive has occurred while the Executive is employed by the Company during the Change of Control Period, it may give to the Executive written notice in accordance with Section 8(d) of its intention to terminate the Executive's employment. In such event, the Executive's employment with the

Company shall terminate effective on the 30th day after receipt of such notice by the Executive, provided that within the 30 days after such receipt the Executive shall not have returned to full-time performance of the Executive's duties.

Section 5. No Set-Off or Mitigation; Resolution of Disputes.

(a) No Set-Off. The Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company may have against the Executive or others.

(b) No Mitigation Required. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement and, except as provided in Section 3(a)(iii), such amounts shall not be reduced whether or not the Executive obtains other employment.

(c) Payments Pending Resolution of Disputes. If there shall be any dispute between the Company and the Executive under this Agreement (i) in the event of any termination of the Executive's employment conflict or inconsistency between this Policy and any other materials distributed by the Company, whether such termination was validly for Cause, or (ii) in this Policy shall govern. In the event of any termination of employment by conflict or inconsistency between this Policy and applicable law(s), the Executive, whether Good Reason existed, then, unless and until there is a final, nonappealable judgment by a court of competent jurisdiction declaring that such termination was for Cause or that the determination by the Executive applicable law(s) shall govern.

You should read this Policy carefully, ask questions of the existence of Good Reason was not made in good faith, the Company shall pay all amounts and provide all benefits to the Executive and/or the Executive's dependents or other beneficiaries, as the case may be, that the Company would be required to pay or provide pursuant to Section 3(a) as though such termination were by the Company other than for Cause, or by the Executive for Good Reason; provided, however, that the Company shall not be required to pay any disputed amount pursuant to this Section 5(c) except upon receipt of an undertaking by or on behalf Company's Office of the Executive to repay all such amounts to which General Counsel, and promptly sign and return the Executive is ultimately adjudged by such court not to be entitled. certification attached as **Annex A**:

(d) Attorney Fees and Expenses. The Company shall pay as they become due all attorney fees and related expenses (including the costs of experts, evidence and counsel) reasonably incurred by the Executive as a result of the Executive seeking to obtain or enforce any right or benefit provided by this Agreement.

Section 6. Excise Tax Limitation.

(a) Notwithstanding anything to the contrary contained in this Agreement, if the payments and benefits provided under this Agreement and benefits provided to, or for the benefit of, the Executive under any other Company plan or agreement (such payments or benefits are collectively referred to as the "***Payments***") would be subject to the excise tax (the "***Excise Tax***") imposed under Section 4999 of the Code, the Payments shall be reduced to the Limited Payment Amount of the greater of (i) the largest amount of Payments that would result in no portion of the Payments being subject to the Excise Tax, or (ii) the largest amount of Payments, up to and including the total Payments, after taking into account all applicable federal, state and local employment taxes, income taxes, and the Excise Tax (all computed at the highest applicable marginal rate), that results in the Executive's receipt, on an after-tax basis, of the greater amount of Payments notwithstanding that all or some portion of the Payments may be subject to the Excise Tax. The intent of the foregoing provision is to reduce the Payments only in the event and to the extent that doing so will maximize the net present value of the Payments, on an after-tax basis, to be received by the Executive. Unless the Executive shall have given prior written notice specifying a different order to the Company to effectuate any reduction in Payments, the Company shall reduce or eliminate the Payments by first reducing or eliminating the portion of the Payments which are not payable in cash and then by reducing or eliminating cash payments, in each case in reverse order beginning with payments or benefits which are to be paid the farthest in time from the Determination (as defined below). Any notice given by the Executive pursuant to the preceding sentence shall take precedence over the provisions of any other plan, arrangement or agreement governing the Executive's rights and entitlements to any benefits or compensation.

(b) The determination of whether the Payments shall be reduced to the Limited Payment Amount pursuant to this Agreement and the amount of such Limited Payment Amount shall be made, at the Company's expense, by an accounting firm selected by the Executive which is one of the five largest accounting firms in the United States (the "***Accounting Firm***"). The Accounting Firm shall provide its determination (the "***Determination***"), together with detailed supporting calculations and documentation, to the Company and the Executive within ten business days of the Termination Date, if applicable, or such other time as requested by the Company or by the Executive (provided that the Executive reasonably believes that any of the Payments may be subject to the Excise Tax), and if the Accounting Firm determines that no Excise Tax is payable by the Executive with respect to the Payments it shall furnish the Executive with an opinion reasonably acceptable to the Executive that no Excise Tax will be imposed with respect to any such Payments. The Determination shall be binding, final and conclusive upon the Company and the Executive.

Section 7. Successors and Assigns.

(a) This Agreement is personal to the Executive and without the prior written consent of the Company shall not be assignable by the Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by the Executive's legal representatives.

(b) This Agreement shall inure to the benefit of and be binding upon the Company and its successors and assigns. The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to the business and/or 50% or more of the assets of the Company (on a consolidated basis) to expressly assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used in this Agreement, the term "***Company***" shall mean the Company as previously defined and any successor to its business and/or assets which assumes and agrees to perform this Agreement by operation of law or otherwise.

Section 8. Miscellaneous.

(a) Governing Law and Venue. This Agreement shall be governed by and construed in accordance with the laws of the State of Colorado, without reference to principles of conflict of laws. Any action brought by any party to this Agreement shall be brought and maintained in a court of competent jurisdiction located in Denver, Colorado.

(b) Captions. The captions of this Agreement are for convenience of reference only, are not part of the provisions hereof and shall have no force or effect in the interpretation of this Agreement.

(c) Amendment. This Agreement may not be amended or modified otherwise than by a written agreement executed by the parties hereto or their respective successors and legal representatives.

(d) Notice. All notices and other communications hereunder shall be in writing and shall be given by hand delivery to the other party or by registered or certified mail, return receipt requested, postage prepaid, addressed as set forth below. Notices and other communications may also be delivered by e-mail to the e-mail address of the recipient set forth below, or to such other e-mail address that the recipient may designate from time to time. Notices delivered by e-mail will be deemed to have been received when the party to whom the e-mail message is addressed acknowledges having received such e-mail notice.

If to the Executive: **Name**
Address
Address
Telefax (print): ______________________

If to the Company: SM Energy Company
1700 Lincoln Street, Suite 3200
Denver, CO Colorado 80203
Attn: Attention: General Counsel

Email: jlebeck@sm-energy.com or to such other address as either party shall have furnished to the other in writing in accordance herewith. Notice and communications shall be effective when actually received by the addressee.

(e) All officers and employees of the Company (on behalf of themselves and their respective Related Persons) must sign and return the certification attached hereto as **Severability** **Annex A**. The invalidity or unenforceability Company's Office of any provision the General Counsel shall also be responsible for administration of this Agreement shall not affect Policy. All determinations and interpretations by the validity or enforceability of any other provision of this Agreement, and any provision that is determined to be invalid or unenforceable Company's General Counsel shall be enforced final and not subject to the maximum extent permissible under law. further review.

(f) I. **Entire Agreement**. This Agreement constitutes the entire agreement between the parties concerning the subject matter hereof. Definitions and Explanations

(g) A. ***Tax Withholding Securities***

Reference in this Policy to "**Company Securities**" includes, without limitation, any securities of the Company, whether or not issued by the Company (such as exchange-traded options). The Any question or uncertainty regarding whether an instrument constitutes a Company Security should be directed to the Office of the General Counsel.

B. Material Nonpublic Information

*1. What Information is "**Material**"?*

It is not possible to define all categories of material information. However, information should be regarded as material if there is a substantial likelihood that it would be considered important to a reasonable investor in making an investment decision regarding a transaction in Company Securities. Information that is likely to affect the price of a Company Security should always be considered material. Either positive or negative information may withhold from any amounts payable under this Agreement such federal, state be material.

There is no bright-line standard for assessing materiality; rather, materiality is based on an assessment of all of the facts and circumstances, and is often evaluated by enforcement authorities with the benefit of hindsight. While it is not possible to define all categories of material information, there are various categories of information that are particularly sensitive and, as a general rule, should be considered material information. Common examples of material information include:

- unpublished financial results (annual, quarterly or local taxes as shall be required otherwise), including, but not limited to, be withheld pursuant to any applicable law revenue results, operating income or regulation. loss, or net income or loss;

(h) • Waiver. The Executive's unpublished projections of future earnings or the Company's failure losses or other earnings guidance, as well as changes to insist upon strict compliance with any provision hereof previously announced guidance or the failure a decision to assert any right the Executive or the Company may have hereunder, including, without limitation, the right of the Executive to terminate employment for Good Reason, shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement. suspend guidance;

- news of a pending or proposed merger, a significant acquisition, a sale of significant assets, a joint venture, a tender or exchange offer, or other material transaction;

- impending announcements of bankruptcy, restructuring or financial liquidity problems;

- news of significant events or developments related to the Company's business, including with respect to its oil and gas properties, such as significant hydrocarbon discoveries or dry holes or changes in estimates of proved reserves;

- gain or loss of a substantial customer or supplier, or disruptions to midstream service providers or other impacting business continuity;
- changes in the Company's distribution or dividend policy, or other stockholder return of capital programs, including stock repurchases;
- stock splits or reverse splits;
- changes in the Company's credit ratings;
- new public or private equity or debt offerings, borrowings, credit facilities or other financing transactions;
- imposition of an event-specific restriction on trading in Company Securities or the securities of another company or the extension or termination of such restriction;
- threatened or new significant litigation;
- significant developments in existing litigation or regulatory proceedings;
- a change in auditors, potential accounting restatements, or a notification that the auditor's reports may no longer be relied upon;
- a significant cybersecurity incident, data breach, or other significant disruption to Company operations; and
- changes in management.

The above list is for illustrative purposes only. If securities transactions become the subject of scrutiny, they will be viewed after-the-fact and with the benefit of hindsight. Therefore, before engaging in any securities transaction, insiders should consider carefully how the Securities and Exchange Commission ("**SEC**") and others might view a transaction in hindsight and with all of the facts disclosed.

*2. What Information is "**Nonpublic**"?*

Information is "**nonpublic**" if it has not been previously disclosed to the general public and is otherwise not generally available to the investing public. In order for information to be considered "**public**," it must be widely disseminated in a manner making it generally available to the investing public and the investing public has had time to absorb the information fully. Generally, one should allow two full Trading Days following publication as a reasonable waiting period before information is deemed to be public.

C. Related Person

"**Related Person**" means, with respect to the Company's insiders:

- any spouse or child (including children away at college and stepchildren), and grandchildren, parents, stepparents, grandparents, siblings and in-laws who reside with the insider;
- anyone else living in the insider's household;
- any person whose securities transactions are directed by the insider;
- any entity influenced or controlled by the insider, including corporations, partnerships, or trusts; and
- estates of which the insider is an executor.

A Company insider who tips information (a "**tipper**") to a person who then trades (a "**tippee**") is subject to the same penalties as the tippee, even if the person did not trade and did not profit from the tippee's trading. Although an insider's parent or sibling may not be considered a Related Person (unless living in the same household as the insider), a parent or sibling may be considered a "tippee" for securities law purposes.

D. Trading Day

"**Trading Day**" means a day on which national stock exchanges or the Over-The-Counter Bulletin Board Quotation System are open for trading. A Trading Day begins at the time trading begins.

II. General Policy

This Policy prohibits insiders from (i) engaging in transactions in Company Securities, whether directly or indirectly through Related Persons, while aware of material nonpublic information about the Company; (ii) trading in the securities of the Company's customers, joint-venture or strategic partners, vendors and suppliers ("**business partners**") if they learn material nonpublic information about such business partners by reason of their employment by, or relationship with, the Company; or (iii) recommending the purchase or sale of Company Securities or tipping or disclosing material nonpublic information to persons within the Company whose jobs do not require them to have that information, or outside of the Company to other persons, including, but not limited to, Related Persons, family, friends, business associates, investors and expert consulting firms, unless any such

disclosure is made in accordance with the Company's policies regarding the protection or authorized external disclosure of information regarding the Company. These illegal activities are commonly referred to as "**insider trading**."

All insiders should treat material nonpublic information about the Company's business partners with the same degree of care required with respect to material nonpublic information related directly to the Company.

A. Trading on Material Nonpublic Information

No Guaranteed Employment insider or Related Person shall engage in any transaction in Company Securities or its business partners' securities, including any offer to purchase or offer to sell, during any period commencing on the date that such person becomes aware of such material nonpublic information, and ending at the beginning of the third Trading Day following the date of public disclosure of the material nonpublic information, or at the time that the information is no longer material.

B. Tipping Others of Material Nonpublic Information

No insider shall disclose or tip material nonpublic information to any other person (including persons inside the Company whose jobs do not require them to have such information or Related Persons) where the material nonpublic information may be used by that person to trade in Company Securities or the securities of its business partners. Further, no insider or Related Person shall make recommendations or express opinions on the basis of material nonpublic information as to trading in Company Securities. Insiders are not authorized to recommend the purchase or sale of Company Securities to any other person regardless of whether the insider is aware of material nonpublic information except in compliance with the Company's Regulation Fair Disclosure Policy.

C. Confidentiality of Material Nonpublic Information

Material nonpublic information relating to the Company is the Company's property and the unauthorized disclosure of material nonpublic information is prohibited. If an insider receives any inquiry from outside the Company (such as a securities analyst) for information (including, without limitation, financial results and/or projections) that may be material nonpublic information, the inquiry should be referred to the Company's Investor Relations Department, which is responsible for coordinating and overseeing the release of that information to the investing public, securities analysts and others in compliance with applicable laws and regulations.

D. Prohibited Transactions

The Company has determined that there is a heightened legal risk and/or the appearance of improper or inappropriate conduct if the insiders subject to this Policy engage in certain types of transactions, namely short-term or speculative transactions in Company Securities. Further, because certain transactions can automatically trigger a purchase or sale of securities at a time when an insider is in possession of material nonpublic information, or disincentivize positive Company stock growth or performance, it is the Company's policy that its insiders may not engage in any of the transactions specified below.

1. *Purchases of Company Stock on Margin or Pledged Securities*. Any of the Company's common stock purchased in the open market should be paid for in full at the time of purchase. Securities held in a margin account may be sold by the broker without the customer's consent if the customer fails to meet a margin call. Similarly, securities pledged as collateral for a loan may be sold in foreclosure

   if the borrower defaults on the loan. Because a margin sale or foreclosure sale could occur at a time when the insider is aware of material nonpublic information, purchasing the Company's securities on margin (*i.e.,* borrowing money from a brokerage firm or other third party to fund the purchase), holding Company Securities in a margin account, or pledging Company Securities as collateral for a loan is strictly prohibited by this Policy.

2. *Short Sales of Company Stock*. Short sales of Company Securities (*i.e.,* the sale of a security that the seller does not own) may evidence an expectation on the part of the seller that the securities will decline in value, and therefore have the potential to signal to the market that the seller lacks confidence in the Company's prospects. In addition, short sales may reduce a seller's incentive to seek to improve the Company's performance. For these reasons, short sales of Company Securities by any insider are strictly prohibited. In addition, Section 16(c) of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**") prohibits the Company's executive officers and directors from engaging in short sales of Company Securities.

3. *Buying or Selling Puts or Calls on Company Stock*. The Executive purchase or sale of options of any kind, whether puts or calls, or other derivative securities relating to Company Securities, is strictly prohibited by this Policy. A put is a right to sell, at a specified price, a specific number of securities by a certain date and may be utilized in anticipation of a decline in the security's value. A call is a right to buy, at a specified price, a specified number of securities by a certain dated and may be utilized in anticipation of a rise in security's value. Puts, calls, and other derivative securities can disincentivize positive Company stock price performance and/or effectuate transactions in Company Securities during times when insiders are in possession of material nonpublic information and are therefore prohibited from engaging in transactions in Company Securities.

4. *Hedging Transactions*. Hedging or monetization transactions designed to hedge or offset any decrease in the market value of securities can be accomplished through a number of possible mechanisms, including through the use of financial instruments such as prepaid variable forward contracts, equity swaps, collars, and exchange funds. Such hedging transactions may permit an insider to continue to own Company Securities without the full risks and rewards of ownership. When that occurs, the insider may no longer have the same objectives as the Company's other stockholders, and therefore, the Company prohibits insiders from engaging in such transactions.

5. *Standing and Limit Orders.* Standing and limit orders instruct brokers to execute transactions based on pre-determined stock price triggers. As a result, insiders have limited control over the timing of purchases or sales, and the broker could execute a transaction when the insider is in possession of material nonpublic information. Except in connection with an approved Rule 10b5-1 Plan, these transactions create heightened risks for insider trading violations similar to the use of margin accounts, and are discouraged; in any event, standing and limit orders should be evaluated carefully and should not have a duration of more than five business days.

6. *Buying or Selling Securities of Business Partners and Certain Other Companies*. If an insider wants to buy or sell any securities of a business partner of the Company, acknowledge a possible acquisition target, or any other company with which you or the Company has a significant relationship, an insider must first determine whether they are aware of any nonpublic information and whether that information is material to that company. If you are ever unsure whether you are aware of material nonpublic information regarding such company, you are advised to err on the side of caution and consult with the Office of the General Counsel.

E. Bona Fide Gifts of Company Securities

Bona fide gifts of Company Securities are not transactions subject to this Policy, unless (i) the person making the gift has reason to believe that the recipient intends to sell the Company Securities while the insider is aware of material nonpublic information, or (ii) the person making the gift is a member of the Window Group subject to the pre-clearance and Blackout restrictions set forth in the Addendum to this Policy.

In addition, because Rule 16a-3 requires companies to report dispositions via gifts on Form 4 within two Trading Days of such disposition, Section 16 officers must immediately report the transaction details of any gifts of Company Securities to the Office of the General Counsel.

F. Post Termination Transactions

If an insider is in possession of material nonpublic information when the insider's service as an employee of the Company terminates, that individual may not engage in transactions in Company Securities until that information becomes widely disseminated to the public, or is no longer material. Questions from former employees about trading in Company Securities should be directed to the Office of the General Counsel.

G. No Hardship Waivers

There are no exceptions to this Policy. Transactions that may be desirable for personal reasons (such as the need for funds for an emergency expenditure), or small transactions, are not excepted from this Policy. Applicable securities laws do not recognize any mitigating circumstances, and even the appearance of an improper transaction must be avoided to preserve the Company's reputation for adhering to the highest standards of conduct.

H. Individual Responsibility

Insiders have ethical and legal obligations to maintain the confidentiality of information about the Company and not to engage in transactions in Company Securities or the securities of its business partners while in possession of material nonpublic information. Each individual is responsible for compliance with this Policy and applicable law, and ensuring that any Related Person whose transactions are subject to this Policy also comply with this Policy and applicable law. In all cases, the responsibility for determining whether an individual is in possession of material nonpublic information, and for otherwise complying with this Policy, rests with that individual and any action on the part of the Company, the General Counsel or any other employee or director pursuant to this Policy (or otherwise) does not in any way constitute legal advice or insulate an individual from liability under applicable securities laws. Insiders could be subject to severe legal penalties and disciplinary action by the Company for any conduct prohibited by this Policy or applicable securities laws, as described below in more detail.

III. Rule 10b5-1 Trading Plans

Rule 10b5-1 under the Exchange Act provides an affirmative defense from insider trading liability under Rule 10b-5. Rule 10b5-1 plans are designed to provide flexibility to those persons who would like to plan securities transactions in advance – at a time when they are not aware of material nonpublic information – and then carry out those pre-planned transactions at a later time, even if they later become aware of material nonpublic information. In order to be eligible to rely on this defense, a person subject to this Policy must enter into a Rule 10b5-1 plan for transactions in Company Securities that meets certain conditions specified in the rule. If the plan meets the requirements of Rule 10b5-1, Company Securities may be purchased, sold or gifted without regard to certain insider trading restrictions.

The requirements of Rule 10b5-1 are as follows:

- During a time when the insider is not aware of material nonpublic information, the insider shall have (a) entered into a binding contract to purchase or sell Company Securities; (b) provided instructions to another person to execute the trade for his or her account; or (c) adopted a written plan for trading in Company Securities (each of which is referred to as a “**Rule 10b5-1 Plan**”).

- The Rule 10b5-1 Plan must: (a) expressly specify the amount of Company Securities (whether a specified number of securities or a specified dollar value of securities) to be purchased or sold on a specific date and/or at a specific price; (b) include a written formula or algorithm, or computer program, for determining the amount of securities (whether a specified number of securities or a specified dollar value of securities), price and/or date range; or (c) provide a third party (*e.g.,* a broker or account manager) who is not aware of material nonpublic

information of the Company with discretion to purchase or sell the securities without any subsequent influence from the insider over how, when or whether to trade.

- The transaction must be made pursuant to the written Rule 10b5-1 Plan. The insider generally cannot deviate from the plan by altering the amount, the price, or the timing of the purchase or sale of Company Securities. Any deviation from, or alteration to, the specifications may render the affirmative defense unavailable. Although deviations from a Rule 10b5-1 Plan are generally not permissible, it is possible for an insider acting in good faith to modify the plan at a time when the insider is unaware of any material nonpublic information. In such a situation, a purchase or sale that complies with the modified plan will be treated as a transaction pursuant to a new plan. Frequent modifications to the Rule 10b5-1 Plan may raise concern about the insider’s good faith in establishing the 10b5-1 Plan, and are strongly discouraged.

- The Rule 10b5-1 Plan must include a cooling-off period before trading can commence that ends on the later of 90 days after adoption of the Rule 10b5- 1 plan or two Trading Days following the disclosure of the Company’s financial results in an SEC periodic report for the fiscal quarter in which the plan was adopted (but in any event, subject to a maximum of 120 days after adoption of the plan).

- An insider may not enter into overlapping Rule 10b5-1 Plans and may only enter into one single-trade plan during any 12-month period.

- The Rule 10b5-1 Plan must include a representation certifying that (i) the insider is not aware of any material nonpublic information; and (ii) the insider is adopting the plan in good faith and not part of a plan or scheme to evade the prohibitions in Rule 10b-5.
- An insider cannot enter into a corresponding or hedging transaction, or alter an existing corresponding or hedging position with respect to the securities to be bought or sold under the Rule 10b5-1 Plan.

Please note that purchases or sales of Company Securities pursuant to a Rule 10b5-1 Plan are <u>not</u> exempt from the short-swing rules set forth in Section 16 under the Exchange Act.

Any Rule 10b5-1 Plan must be approved by the Office of the General Counsel prior to entering into the plan, and entry into a Rule 10b5-1 Plan by members of the Window Group (as discussed in the Addendum to the Policy) is subject to the Company’s Trading Window and pre-clearance requirements (as described in the Addendum).

IV. Transactions Under Company Plans

This Policy does not apply in the case of the following transactions, except as may otherwise be provided under any other written agreement between specifically noted:

Restricted Stock Awards. This Policy does not apply to the Executive and vesting of restricted stock, or the exercise of a tax withholding right pursuant to which a person elects to have the Company concerning withhold shares of stock to satisfy tax withholding requirements upon the Executive’s vesting of any restricted stock. The Policy does apply, however, to any market sale of restricted stock.

Employee Stock Purchase Plan. This Policy does not apply to purchases of Company Securities in the employee stock purchase plan resulting from an insider’s periodic contribution of money to the plan pursuant to an election made at the time of enrollment in the plan. This Policy also does not apply to purchases of Company Securities resulting from lump sum contributions to the plan, provided that an insider elected to participate by lump sum payment at the beginning of the applicable enrollment period. This Policy does apply, however, to (i) an election to participate in the plan for any enrollment period; (ii) any modification to the initial election to participate in the plan, or the withdrawal of amounts previously contributed to the plan; and (iii) sales of Company Securities purchased pursuant to the plan.

V. Potential Criminal and Civil Liability and/or Disciplinary Action

A. SEC Enforcement Action

The adverse consequences of insider trading violations can be staggering and currently include, without limitation, the following:

1. For individuals who trade on material nonpublic information (or tip information to others):

    - disgorgement of profits or losses avoided;

    - a civil penalty of up three times the profit gained or loss avoided resulting from the violation;

- a criminal fine of up to $5 million (no matter how small the profit); and/or
- a jail term of up to 20 years.

2. For a company (as well as possibly any supervisory person) that fails to take appropriate steps to prevent illegal trading:

- disgorgement of profits or losses avoided;
- a civil penalty of up to the greater of $1 million or three times the profit gained or loss avoided as a result of the insider's violation;

- a criminal penalty of up to $25 million; and/or
- the civil penalties may extend personal liability to the Company's directors, officers and other supervisory personnel if they fail to take appropriate steps to prevent insider trading.

B. Disciplinary Action by the Company

Persons who violate this Policy shall be subject to disciplinary action by the Company, up to and including termination of employment.

This document states a policy of SM Energy Company and is not intended to be regarded as the rendering of legal advice.

ANNEX A
SECURITIES TRADING POLICY
CERTIFICATION

I have read and understand the Securities Trading Policy (the "**Policy**") of SM Energy Company (the "**Company**"). I agree, on behalf of myself and my Related Persons, that I will comply with the policies and procedures set forth in the Policy. I understand and agree that, if I am an employee of the Company or one of its subsidiaries or other affiliates, my failure (or the failure of any of my Related Persons) to comply in all respects with the Company's policies, including the Policy, is a basis for termination of my employment with the Company and any subsidiary or other affiliate to which my employment now relates or may in the provisions of such other agreement not inconsistent herewith which shall remain future relate.

I am aware that this signed Certification will be filed with my personnel records in full force and effect, the employment of the Executive by the Company is "at will" and, prior to the Change of Control Date, may be terminated by either the Executive or the Company at any time.Company's Human Resources Department.

(j) Execution in Counterparts and by Facsimile. This Agreement may be executed in counterparts and signature pages may be delivered by facsimile transmission.

____
Signature

____
Type or Print Name

____
Date

* * * * *

IN WITNESS WHEREOF, this Change of Control Executive Severance Agreement is hereby duly executed by each party hereto as of the day and year first above written.

COMPANY:

SM ENERGY COMPANY

By: ____
James B. Lebeck, Senior Vice President and General Counsel

EXECUTIVE:

Name

EXHIBIT 10.22

SM ENERGY COMPANY

PERFORMANCE SHARE UNIT AWARD AGREEMENT

This Performance Share Unit Award Agreement (the "***Agreement***") is made effective as of ____________ (the "***Award Date***"), by and between SM Energy Company, a Delaware corporation (the "***Company***") andthe "***Participant***" (identified below) to whom performance share units have been awarded under the Company's Equity Incentive Compensation Plan, as amended (the "***Plan***"). Capitalized terms used but not defined in this Agreement shall have the meanings given to them in the Plan.

Pursuant to the terms of the Plan and this Agreement, as of the Award Date, the Company has made the following award (the "***Award***") to the Participant ofperformance share units (the "***Performance Units***"):

Participant:

Units Awarded:

ARTICLE I

PERFORMANCE UNITS

1.1 Performance Units and Performance Period. The Performance Units represent the right to receive, upon the payment of the Performance Units pursuant to Section 1.4 hereof after the completion of the Performance Period (as defined below), a number of shares of the Company's common stock, $.01 par value per share (sometimes referred to herein as the "***Common Stock***"), that will be calculated as set forth in Section 1.2 below based on the extent to which the Company's Performance Criteria (as defined in Section 1.2) have been achieved and the extent to which the Performance Units have vested. Any Common Stock that is issued pursuant to any provision of this Agreement may be referred to in this Agreement as a "***Share***" or "***Shares***." Such actual number of Shares that may be issued upon payment of the Performance Units may be from zero (0) to two (2.0) times the number of Performance Units granted on the Award Date. The number of Performance Units granted herein may be referred to as the "target" number of Shares. The performance period (the "***Performance Period***") for the Performance Units shall be the three (3) year period beginning on ________, and ending on ________.* Performance Units are intended to be Performance Shares as defined in the Plan.

1.2 Determination of Number of Shares Earned.

(a) Performance Criteria. The actual number of Shares that may be earned and issued upon payment of the Performance Units after completion of the Performance Period shall be based upon the Company's achievement of performance criteria (the "Performance Criteria") established by the Compensation Committee of the Board of Directors of the Company (the "Committee") for the Performance Period in accordance with the terms of the Plan and as set forth below and reflected in the payout design (the "Payout Design") attached as Appendix A hereto. The Performance Criteria for the calculation of the actual number of Shares to be issued upon payment of the Performance Units as reflected in the Payout Design are based on a combination of (i) the gross amount of free cash flow generated by the Company during the Performance Period; (ii) the relative measure of the Company's cumulative total shareholder return ("TSR") and associated Compound Annual Growth Rate ("CAGR") for the Performance Period compared with the cumulative TSR and CAGR of the Peer Companies (as defined below) for the Performance Period; (iii) the Company's absolute TSR for the Performance Period; and (iv) the Company's performance for the Performance Period with respect to the following metrics: reduction of greenhouse gas emissions intensity, employee and contractor safety, and spill performance.

(b) Calculation of the Performance Criteria. The calculation of the Performance Criteria for the Performance Period shall be in accordance with the methodology adopted by the Committee in its sole discretion.

(c) Peer Companies. The "***Peer Companies***" shall consist of those exploration and production companies selected by the Committee in its sole discretion at the initiation of the Performance Period, as such group may be modified from time to time during the Performance Period by the Committee in its sole discretion.

* With respect to the GHG Emissions Intensity Reduction metric, the performance period will begin on ________ and end on ___________, with the percentage reduction being determined by comparison of the Company's GHG Emissions Intensity for the full year ____ to the Company's GHG Emissions Intensity for the full year ____.

CERTIFICATION TO SM ENERGY SECURITIES TRADING POLICY

ADDENDUM TO SM ENERGY COMPANY
SECURITIES TRADING POLICY

(This Addendum (this "**d)** **Addendum**Payout Design. The Payout Design attached as **Appendix A** hereto sets forth the possible multipliers, which range from zero percent (0% ") to two hundred percent (200%), that may be applied to the number of vested Performance Units to determine the actual number of Shares to be issued upon payment of the vested Performance Units after the completion of the Performance Period. The final multiplier SM Energy Company Securities Trading Policy (the "**Final Multiplier** **Policy**") shall be determined by the Committee after the completion applies to members of the Performance Period based on the Company's performance with respect to the Performance Criteria. Subject to Section 1.2(e), the number of Shares, if any, that shall be issued to the Participant upon payment of the Performance Units shall be calculated as an amount equal to (A) the number of Performance Units that have vested in accordance with Section 1.3 or Section 1.6 hereof, multiplied by (B) the Final Multiplier, as determined by the Committee in accordance with the Payout Design (such number of Shares, the "***Payout Shares***"). Any fractional Shares which would otherwise result from application of the Final Multiplier shall be rounded up to the nearest whole Share of Common Stock.

(e) Payout Value Limit. Notwithstanding any other provision of this Agreement, under no circumstances shall (i) the product of (A) the number of Payout Shares as calculated in accordance with the Payout Design under the provisions of Section 1.2(d), multiplied by (B) the per share closing price of the Company's Common Stock on ___________, as reported by the principal exchange or market on which the Company's Common Stock is then traded (the "***Payout Closing Price***") (with such product referred to as the "Payout Design Value"), exceed (ii) the product of (C) the number of Performance Units multiplied by (D) $[______] [1] (with such product referred to as the "Payout Value Limit"). If the Payout Design Value would otherwise exceed the Payout Value Limit, then the number of Payout Shares shall be reduced to an amount equal to (x) the Payout Value Limit divided by (y) the Payout Closing Price, with any fractional Shares that would otherwise result from such computation to be rounded up to the nearest whole Share of Common Stock.

1.3 Vesting of Performance Units.

(a) Vesting. Subject to the provisions contained herein, the Performance Units shall fully vest on __________ (the "***PSU Vesting Schedule***"). In addition, the Performance Units may become fully vested or be forfeited under certain circumstances specified in this Agreement. As of the Award Date, the Participant must be an employee of the Company or a subsidiary thereof. If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Performance Units pursuant to the PSU Vesting Schedule, the Participant shall forfeit the unvested Performance Units under the Award, except as otherwise provided in this Section 1.3 and Section 1.6.

(b) Acceleration Upon Death or Total Disability. The Performance Units shall become fully vested, notwithstanding any other provisions of this Section 1.3, upon termination of the Participant's employment with the Company or a subsidiary thereof because of death or Total Disability (as defined below). Any such acceleration of the vesting of the Performance Units pursuant to this Section 1.3(b) will not result in an acceleration of the PSU Payment Date, because the number of Shares earned from the Performance Units shall be calculated after the completion of the Performance Period. For purposes of this Agreement, "***Total Disability***" means a medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, by reason of which the Participant is unable to engage in any substantial gainful activity or is receiving income replacement benefits for a period of not less than three (3) months under an accident and health plan covering employees of the Company.

(c) Pro Rata Vesting. If the Participant is at least sixty (60) years of age and has completed at least ten (10) years of service with the Company as of the Award Date, then notwithstanding Section 1.3(a), the Performance Units shall vest in a prorated manner determined by dividing the number of days between the first day of the Performance Period and the date of Participant's retirement by the total number of days in the Performance Period. For example:

[1]
To be inserted. Equal to [_________ trailing 20-day vwap] * (1.5)3 * 2

Participant's Award = 1,000 Performance Units

Number of Days in Performance Period = 1,095
Number of Days between beginning of Performance Period and Participant's Retirement = 475
475/1095 = 0.4337
1,000 * 0.4337 = 434 Performance Units Vested

If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Performance Units pursuant to this Section 1.3(c), the Participant shall forfeit all unvested Performance Units under the Award, except as otherwise provided in this Section 1.3 and Section 1.6.

(d) Termination for Cause. Notwithstanding any other provisions of this Section 1.3, the Participant shall forfeit all the Performance Units under this Award upon the termination of the employment of the Participant by the Company or a subsidiary thereof prior to the completion of the Performance Period for "cause," which term is specifically not capitalized as such term is in Section 1.6(a) of this Agreement, it being the specific intent of the Company and the Participant that "cause" in this instance shall be broadly defined as any event, action, or inaction by or attributed to the Participant that could reasonably be the basis for an employer to terminate the employment of the affected individual.

1.4 Payment of Performance Units. Following the last day of the Performance Period and prior to the payment of the earned and vested Performance Units on or about the PSU Payment Date, the Committee shall determine, (i) the extent to which the Performance Criteria have been achieved over the Performance Period, and (ii) the Final Multiplier. Subject to Section 1.2(e), the Final Multiplier shall then be applied to the number of vested Performance Units to determine the number of Payout Shares (also sometimes referred to herein as the "***Earned Shares***"), if any, to be issued to the Participant in payment of the Performance Units. The determination of the Earned Shares by the Committee shall be binding on the Participant and conclusive for all purposes. The Earned Shares, if any, shall be issued to the Participant in payment of the Performance Units on or about ___________ (the "***PSU Payment Date***"). Upon the payment of the Performance Units, the Company shall deliver to the Participant evidence of book-entry Shares or a certificate for the number of Shares issued to the Participant in payment of the Performance Units. The Earned Shares shall not be subject to any holding or transfer restrictions after payment of the Performance Units.

1.5 Transfer Restrictions for Unpaid Performance Units. Performance Units that have not been paid shall not be transferable by the Participant, and the Participant shall not be permitted to sell, transfer, pledge, assign, or otherwise alienate or encumber such Performance Units or the Shares issuable in payment thereof, other than (i) to the person or persons to whom the Participant's rights under such Performance Units pass by will or the laws of descent and distribution, (ii) to the spouse or the descendants of the Participant or to trusts for such persons to whom or which the Participant may transfer such Performance Units by gift, (iii) to the legal representative of any of the foregoing, or (iv) pursuant to a qualified domestic relations order as defined under Section 414(p) of the Internal Revenue Code of 1986, as amended (the "***Code***") or a similar order or agreement pursuant to state domestic relations law (including a community property law) relating to the provision of child support, alimony payments, or marital property rights to a spouse, former spouse, child, or other dependent of the Participant. Any such transfer shall be made only in compliance with the Securities Act of 1933 and the requirements therefor as set forth by the Company. Any attempted transfer in contravention of the foregoing provisions shall be null and void and of no effect.

1.6 Change of Control Termination.

(a) Vesting upon Change of Control Termination. Notwithstanding any other provision of this Agreement, the Performance Units shall become fully vested upon a Change of Control Termination in accordance with this Section 1.6. If, in connection with the occurrence of a Change of Control, the Performance Units are assumed or continued by the acquiror, then upon such Change of Control the Performance Units shall be deemed earned at their target value (100%) but shall remain subject to the remaining terms and conditions herein, including all time-based vesting requirements, but without any further performance-based vesting requirements. For purposes of this Agreement, a "Change of Control Termination" occurs upon the termination of the Participant's employment with the Company or a subsidiary or successor thereof in the event that (i) a Change of Control (as defined in the Plan) of the Company occurs, and (ii) the Participant's employment with the Company or a subsidiary or successor thereof is subsequently terminated without Cause (as defined below) or the Participant terminates his or her employment with the Company or a subsidiary or successor thereof for Good Reason (as defined below), and such termination of employment occurs prior to the normal completion of vesting of the Performance Units at the end of the Performance Period. If the Participant has entered into a separate written Change of Control Executive Severance Agreement or Change of Control Severance Agreement (with either to be subsequently referred to herein as a "***Change of Control Severance Agreement***") with the Company, the

terms "Cause" and "Good Reason" used herein shall have the meanings set forth in such Change of Control Severance Agreement. If the Participant has not entered into a separate written Change of Control Severance Agreement, the terms "Cause" and "Good Reason" used herein shall have the meanings set forth in the Company's Change of Control Severance Plan (the "***Change of Control Severance Plan***").

(b) Payment upon Change of Control Termination. Notwithstanding any other provisions of this Agreement to the contrary, in the event of a Change of Control Termination with respect to the Participant's employment with the Company or a subsidiary or successor thereof as set forth in Section 1.6(a) above, the target value of the Award shall be paid to the Participant in cash within thirty (30) days following the effective date of the Change of Control Termination; provided, however, that the time and manner of such payment shall comply with Section 409A of the Code as referred to in Section 2.11 of this Agreement.

ARTICLE II

GENERAL PROVISIONS

2.1 Adjustments Upon Changes in Capitalization. In the event that a stock split, stock dividend, or other similar change in capitalization of the Company occurs, the number and kind of Shares that may be issued under this Agreement and that have not yet been issued shall be proportionately and appropriately adjusted.

2.2 No Dividend Equivalents or Stockholder Rights Until Shares Issued. The Performance Units shall not be credited with Dividend Equivalents. In addition, the Participant shall have no voting, transfer, liquidation, or other rights of a holder of Shares with respect to the Performance Units until such time as Shares, if any, have been issued by the Company to the Participant in payment of the Performance Units. Until the Performance Units are paid or terminated, they will represent only bookkeeping entries by the Company to evidence unfunded and unsecured obligations of the Company.

2.3 Notices. Any notice to the Participant relating to this Agreement shall be in writing and delivered in person, by mail, or by email transmission to the address or addresses on file with the Company. Any notice to the Company shall be in writing and delivered in person or by mail to the Company at the address below and specifically directed to the attention of the General Counsel with a copy to the Human Resources Department. Anyone to whom a notice may be given under this Agreement may designate a new address by notice to that effect.

If to the Company:
SM Energy Company
1700 Lincoln Street, Suite 3200
Denver, CO 80203
Attention: General Counsel

With a copy to:
SM Energy Company
1700 Lincoln Street, Suite 3200
Denver, CO 80203
Attention: Human Resources Department

2.4 Benefits of Agreement. This Agreement shall inure to the benefit of and be binding upon each successor of the Company and the Participant's heirs, legal representatives, and permitted transferees. This Agreement and the Plan shall be the sole and exclusive source of any and all rights that the Participant and the Participant's heirs, legal representatives, and permitted transferees may have with respect to this Award, the Performance Units, and the Plan.

2.5 Resolution of Disputes. Any dispute or disagreement that arises under, or is a result of, or in any way relates to, the interpretation, construction, or applicability of this Agreement shall be resolved as determined by the Committee, or the Board of Directors of the Company (the "**Board**"), or by any other committee appointed by the Board for such purpose. Any determination made hereunder shall be final, binding, and conclusive for all purposes.

2.6 Controlling Documents. The provisions executive officers subject to Section 16 of the Plan are hereby incorporated into this Agreement by reference. In the event Securities Exchange Act of any inconsistency between this Agreement 1934, as amended (the "**Exchange Act**"), and the Plan, the Plan shall control.

2.7 Amendments. This Agreement may be amended only by a written instrument executed by both certain other designated employees and consultants of the Company and the Participant.

2.8 No Right of Participant who regularly have access to Continued Employment. Nothing contained in this Agreement or the Plan shall confer on the Participant any right to continue to be employed by the Company or any subsidiary thereof, or shall limit the Company's right to terminate the employment of the Participant at any time.

2.9 Vesting Dates and Payment Dates. In the event that any vesting date, payment date, or any other measurement date with respect to this Award does not fall on a business day, such date shall be deemed to occur on the next following business day.

2.10 Tax Withholding. The Company may make such provisions and take such steps as it deems necessary or appropriate for the withholding of any taxes that the Company is required by law or regulation of any governmental authority, whether Federal, state, or local, to withhold in connection with the Performance Units or Shares subject to this Agreement. The Participant shall elect, prior to any tax withholding event related to this Award and at a time when the Participant is not aware of any material nonpublic information about the Company (the "**Window Group**"). The General Counsel of SM Energy Company shall determine the composition of the Window Group and may add or remove persons from the Participant would be permitted Window Group from time to engage time as deemed appropriate.

This Addendum is in a transaction in the Company's securities under addition to and supplements the Company's Securities Trading Policy, whether the Participant will satisfy all or part of such tax withholding requirement by paying the taxes in cash or by having the Company withhold Shares having a fair market value equal to the minimum statutory withholding that may be imposed on the transaction (based on minimum statutory withholding rates for Federal, state, and local tax purposes, as applicable, that are applicable to such transaction). The Participant's election shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate. If Participant fails to make an election, the Company will withhold Shares having a fair market value equal to the minimum statutory withholding that may be imposed on the transaction, as provided above. For purposes of tax withholding pursuant to this Section 2.10, unless applicable laws and regulations dictate otherwise, the Company shall determine fair market value based on the closing price of a Share as reported on the New York Stock Exchange or other applicable public market on the business day immediately preceding the PSU Payment Date.

2.11 Compliance with Section 409A of the Code. Notwithstanding any provision in this Agreement to the contrary, to the extent that this Agreement constitutes a nonqualified deferred compensation plan or arrangement to which Section 409A of the Code applies, the administration of this Award (including the time and manner of payments under the Award and this Agreement) shall comply with Section 409A of the Code. In connection therewith, any payment to the Participant with respect to the Award under this Agreement which Section 409A(a)(2)(B)(i) of the Code indicates may not be made before the date which is six months after the date of the Participant's separation from employment service (the "***Section 409A Six-Month Waiting Period***"), as a result of the fact that the Participant is a specified key employee referred to in Section 409A(a)(2)(B)(i) of the Code, shall not occur or be made during the Section 409A Six-Month Waiting Period but rather shall be delayed, if such payment would otherwise occur during the Section 409A Six-Month Waiting Period, until the expiration of the Section 409A Six-Month Waiting Period. Except as provided under Section 1.3(a), the Participant will not be considered to have a termination of employment or separation from employment under this Agreement unless the termination of employment or separation from employment constitutes a "separation from service" under Treasury Regulation Section 1.409A-1(h).

2.12 Personal Data. The Participant hereby consents to the collection, use, and transfer, in electronic or other form, of the Participant's Personal Data by and among, as applicable, the Company and its affiliates for the exclusive purpose of implementing, administering, and managing the Participant's participation in the Plan. The Company holds, or may receive from any agent designated by the Company, certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social security insurance number or other identification number, salary, nationality, job title, any shares of Common Stock held, details of this Award and any other rights to shares of Common Stock awarded, canceled, exercised, vested, unvested, or outstanding in the Participant's favor, for the purpose of implementing, administering, and managing the Plan, including complying with applicable tax and securities laws (the "***Personal Data***"). The Personal Data may be transferred to any third parties assisting in the implementation, administration, and management of the Plan. The Participant authorizes such recipients of the Personal Data to receive, possess, use, retain, and transfer the Personal Data, in electronic or other form, for the purposes described above, and the Participant hereby releases the Company and its affiliates from any of the Participant's claims related to the use or disclosure of such Personal Data. The Participant may, at any time, view the Personal Data, request additional information about the storage and processing of the Personal Data, require any necessary amendments to the Personal Data, or refuse or withdraw the consents herein, in any case without cost, by contacting the Corporate Secretary of the Company in writing. Any such refusal or withdrawal of the consents herein may affect the Participant's ability to participate in the Plan.

2.13 Electronic Delivery of Documents. The Company may, in its sole discretion, deliver any documents related to this Award, or any future awards that may be granted under the Plan, by electronic means, or request the Participant's consent to participate in the Plan or other authorizations from the Participant in connection therewith by electronic means. The Participant hereby consents to receive such documents by electronic delivery and, if requested, to participate in the Plan through an on-line or electronic system established and maintained by the Company or another third party designated by the Company.

2.14 Receipt of Award and Related Documents. The Participant hereby acknowledges the receipt, either directly or electronically, of the Award, a copy of the Plan, and a prospectus for the Plan.

2.15 Execution and Counterparts. This Agreement may be executed in counterparts. Execution of this Agreement may be evidenced by any appropriate form of electronic signature or affirmative email or other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication of the intention by such party to execute or adopt such instrument for purposes of execution hereof.

* * * * *

[Signature page follows]

IN WITNESS WHEREOF, the Company and the Participant have caused this Performance Share Unit Award Agreement to be entered into effective as of the Award Date.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By: _______________________________________
Printed Name: James B. Lebeck
Title: Senior Vice President and General Counsel
Date Signed: _______________

PARTICIPANT:

Signature: ________________________________
Printed Name:

EXHIBIT 10.23

SM ENERGY COMPANY

RESTRICTED STOCK UNIT AWARD AGREEMENT

This Restricted Stock Unit Award Agreement (the "***Agreement***") is made effective as of ___________ (the "***Award Date***"), by and between SM Energy Company, a Delaware corporation (the "***Company***"), and the "***Participant***" (identified below) to whom restricted stock units have been awarded under the Company's Equity Incentive Compensation Plan, as amended (the "***Plan***"). Policy. Capitalized terms used but not defined in this Agreement Addendum shall have the respective meanings given to them such terms in the Plan.

Pursuant to the terms of the Plan and this Agreement, as of the Award Date, the Company has made the following award (the "***Award***") to the Participant of restricted stock units (the "***Units***"):

Participant:

Units Awarded:

ARTICLE I

RESTRICTED STOCK UNITS

1.1 Units. Each Unit represents the right to receive one share of the Company's common stock, $.01 par value per share (sometimes referred to herein as the "***Common Stock***"), to be delivered upon settlement of the Units as set forth in Section 1.3 below, subject to the terms and conditions set forth in the Plan and this Agreement. Any Common Stock that is issued pursuant to any provision of this Agreement may be referred to in this Agreement as a "***Share***" or "***Shares***."

1.2 Vesting of Units.

(a) Vesting. Subject to the provisions contained herein, the Units shall vest as follows (the "RSU Vesting Schedule"):

1/3rd on ___________
1/3rd on ___________
1/3rd on ___________

In addition, the Units may become fully vested or be forfeited under certain circumstances specified in this Agreement. As of the Award Date, the Participant must be an employee of the Company or a subsidiary thereof. If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Units pursuant to the RSU Vesting Schedule, the Participant shall forfeit the remaining unvested Units under the Award, except as otherwise provided in this Section 1.2 and Section 1.5.

(b) Acceleration Upon Death or Total Disability. The Units shall become fully vested, notwithstanding any other provision of this Section 1.2, upon termination of the Participant's employment with the Company or a subsidiary thereof because of death or Total Disability (as defined below).

(c) For purposes of this Agreement, "***Total Disability***" means a medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, by reason of which the Participant is unable to engage in any substantial gainful activity or is receiving income replacement benefits for a period of not less than three (3) months under an accident and health plan covering employees of the Company.

(d) Pro Rata Vesting. If the Participant is at least sixty (60) years of age as of the Award Date, then notwithstanding Section 1.2(a), the Units shall vest as follows (the "***Pro Rata Vesting Schedule***"):

___________ 1/6th
___________ 1/6th
___________ 1/6th
___________ 1/6th
___________ 1/6th

___________ 1/6th

If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Units pursuant to the Pro Rata Vesting Schedule, the Participant shall forfeit the unvested Units under the Award, except as otherwise provided in this Section 1.2 and Section 1.5.

(e) Termination for Cause. Notwithstanding any other provision of this Section 1.2, the Participant shall forfeit any unvested and unsettled Units under this Award upon the termination of the employment of the Participant by the Company or a subsidiary thereof for cause, which term is specifically not capitalized as such term is in Section 1.5(a) of this Agreement, it being the specific intent of the Company and the Participant that "cause" in this instance shall be broadly defined as any event, action, or inaction by or attributed to the Participant that could reasonably be the basis for an employer to terminate the employment of the affected individual.

1.3 Settlement of Units.

(a) RSU Vesting Schedule Settlement. The portion of the Units that vest on a particular vesting installment date pursuant to Section 1.2(a) shall be settled on such vesting installment date, provided that such portion of the Units has not been previously terminated.

(b) Accelerated Settlement. In the event of acceleration of the vesting of the Units pursuant to Section 1.2(b), the Units will be settled within thirty (30) days following the Participant's termination of employment with the Company.

(c) Pro Rata Vesting Settlement. In the event that the Units vest pursuant to Section 1.2(d), the portions of Units that are vested shall be settled on the earlier to occur of (i) within thirty (30) days following termination of the Participant's employment with the Company or (ii) the next applicable date set forth in the RSU Vesting Schedule in Section 1.2(a).

(d) For purposes of this Agreement, "***RSU Settlement Date***" means each date upon which Units are settled pursuant to Sections 1.3(a), 1.3(b) or 1.3(c).

(e) Settlement of the vested Units may be made (i) solely through the issuance of Shares or (ii) at the mutual election of the Participant and the Company, in a combination of Shares and cash. The cash value of Units settled in cash shall be based on the closing price of a Share as reported on the New York Stock Exchange or other applicable public market on the trading day corresponding to the RSU Settlement Date. Upon the settlement of the Units through the issuance of Shares, the Company shall deliver to the Participant evidence of book-entry Shares. The Shares shall not be subject to any holding or transfer restrictions after settlement of the Units. The Participant shall not be permitted to elect to further defer settlement beyond the RSU Settlement Date.

1.4 Transfer Restrictions. Outstanding Units that have not been settled shall not be transferable by the Participant, and the Participant shall not be permitted to sell, transfer, pledge, assign, or otherwise alienate or encumber such Units or the Shares issuable in settlement thereof, other than (i) to the person or persons to whom the Participant's rights under such Units pass by will or the laws of descent and distribution, (ii) to the spouse or the descendants of the Participant or to trusts for such persons to whom or which the Participant may transfer such Units by gift, (iii) to the legal representative of any of the foregoing, or (iv) pursuant to a qualified domestic relations order as defined under Section 414(p) of the Internal Revenue Code of 1986, as amended (the "***Code***"), or a similar order or agreement pursuant to state domestic relations law (including a community property law) relating to the provision of child support, alimony payments, or marital property rights to a spouse, former spouse, child, or other dependent of the Participant. Any such transfer shall be made only in compliance with the Securities Act of 1933 and the requirements therefor as set forth by the Company. Any attempted transfer in contravention of the foregoing provisions shall be null and void and of no effect.

1.5 Change of Control Termination.

(a) Vesting Upon Change of Control Termination. Notwithstanding any other provision of this Agreement, the Units shall become fully vested upon a Change of Control Termination. For purposes of this Agreement, a "***Change of Control Termination***" occurs upon the termination of the Participant's employment with the Company or a subsidiary or successor thereof in the event that (i) a Change of Control (as defined in the Plan) of the Company occurs, and (ii) the Participant's employment with the Company or a subsidiary or successor thereof is subsequently terminated without Cause (as defined below) or the Participant terminates his or her employment with the Company or a subsidiary or successor thereof for

Good Reason (as defined below), and such termination of employment occurs prior to the normal completion of vesting of the Units. The normal vesting and settlement provisions in Article I of this Agreement shall not be affected by the first sentence of this subsection if a Change of Control of the Company occurs but there is not also a Change of Control Termination with respect to the Participant's employment with the Company or a subsidiary or successor thereof on or before the date on which the Units become fully vested as provided in Section 1.2 above. If the Participant has entered into a separate written Change of Control Executive Severance Agreement or Change of Control Severance Agreement (with either to be subsequently referred to herein as a "***Change of Control Severance Agreement***") with the Company, the terms "Cause" and "Good Reason" used herein shall have the meanings set forth in such Change of Control Severance Agreement. If the Participant has not entered into a separate written Change of Control Severance Agreement, the terms "Cause" and "Good Reason" used herein shall have the meanings set forth in the Company's Change of Control Severance Plan (the "***Change of Control Severance Plan***").

(b) Settlement upon Change of Control Termination. Notwithstanding any other provision of this Agreement to the contrary, in the event of a Change of Control Termination with respect to the Participant's employment with the Company or a subsidiary thereof as set forth in Section 1.5(a) above, the vested Units shall be settled either in Shares or in cash of equivalent value, as determined by the Compensation Committee of the Board of Directors (the "***Committee***") or other duly authorized administrator of the Plan, in its discretion, within thirty (30) days following the effective date of the Change of Control Termination; provided, however, that the time and manner of such settlement shall comply with the Section 409A Six-Month Waiting Period, as defined in Section 2.11 of this Agreement.

ARTICLE II

GENERAL PROVISIONS

2.1 Adjustments Upon Changes in Capitalization. In the event that a stock split, reverse stock split, stock dividend, or other similar change in capitalization of the Company occurs, the number and kind of Shares that may be issued under this Agreement and that have not yet been issued shall be proportionately and appropriately adjusted.

2.2 No Dividend Equivalents or Stockholder Rights Until Shares Issued. The Units shall not be credited with Dividend Equivalents. In addition, the Participant shall have no voting, transfer, liquidation, or other rights of a holder of Shares with respect to the Units until such time as Shares, if any, have been issued by the Company to the Participant in settlement of the Units. Until the Units are settled or terminated, they will represent only bookkeeping entries by the Company to evidence unfunded and unsecured obligations of the Company.

2.3 Notices. Any notice to the Participant relating to this Agreement shall be in writing and delivered in person, by mail, or by email transmission to the address or addresses on file with the Company. Any notice to the Company shall be in writing and delivered in person or by mail to the Company at the address below, and specifically directed to the attention of the General Counsel with a copy to the Human Resources Department. Anyone to whom a notice may be given under this Agreement may designate a new address by notice to that effect.Policy Statement.

If you have been informed that you are a member of the Window Group, you should read this Addendum to the Company Policy carefully, ask questions of the Company's General Counsel, and promptly sign and return the certification attached as **: Annex A to this Addendum**to:

SM Energy Company
1700 Lincoln Street, Suite 3200
Denver, CO Colorado 80203
Attention: General Counsel

With a copy to:

SM Energy Company
1700 Lincoln Street, Suite 3200
Denver, CO 80203
Attention: Human Resources Department

2.4 I. Benefits of Agreement. This Agreement shall inure to the benefit of Additional Trading Guidelines and be binding upon each successor Requirements for Members of the Company and the Participant's heirs, legal representatives, and permitted transferees. This Agreement and the Plan shall be the sole and exclusive source of any and all rights that the Participant and the Participant's heirs, legal representatives, and permitted transferees may have with respect to this Award, the Units, and the Plan.

2.5 Resolution of Disputes. Any dispute or disagreement that arises under, or is a result of, or in any way relates to, the interpretation, construction, or applicability of this Agreement shall be resolved as determined by the Committee, or the Board of Directors of the Company (the "***Board***"), or by any other committee appointed by the Board for such purpose. Any determination made hereunder shall be final, binding, and conclusive for all purposes. Window Group

2.6 A. ***Controlling Documents***. The provisions of the Plan are hereby incorporated by reference into this Agreement. In the event of any inconsistency between this Agreement Blackout Period and the Plan, the Plan shall control. Trading Window

2.7 1. *Amendments Quarterly Restrictions.* . This Agreement may be amended only by a written instrument executed by both The period beginning at the Company and the Participant.

2.8 No Right close of Participant to Continued Employment. Nothing contained in this Agreement or the Plan shall confer market on the Participant any right 10th calendar day prior to continue the end of each fiscal quarter or year and ending at the beginning of the third Trading Day following the date of public disclosure of the financial results for that fiscal quarter ("**Blackout Period**") is a particularly sensitive period of time for transactions in Company Securities from the perspective of compliance with applicable securities laws. This sensitivity is due to be employed the fact that certain insiders identified by the Company or any subsidiary thereof, or shall limit will, during the Company's right to terminate the employment of the Participant at any time.

2.9 Vesting Dates and Settlement Dates. In the event that any vesting date, settlement date, or any other measurement date with respect to this Award does not fall on a business day, such date shall Blackout Period, often be deemed to occur on the next following business day.

2.10 Tax Withholding. The Company may make such provisions and take such steps as it deems necessary or appropriate for the withholding of any taxes that the Company is required by law or regulation of any governmental authority, whether Federal, state, or local, to withhold in connection with the Units or Shares subject to this Agreement. The Participant shall elect, prior to any tax withholding event related to this Award and at a time when the Participant is not aware of any material nonpublic information about the expected financial results for the quarter.

To ensure compliance with this Addendum and applicable federal and state securities laws, **members of the Window Group are strictly prohibited from transacting in Company Securities during the Blackout Period**, and may only execute such transactions during the Participant would be permitted to engage in a transaction in period commencing at the Company's securities under the Company's Securities Trading Policy, whether the Participant will satisfy all or part open of such tax withholding requirement by paying the taxes in cash or by having the Company withhold Shares having a fair market value equal to the minimum statutory withholding that may be imposed on the transaction (based on minimum statutory withholding rates for Federal, state, and local tax purposes, as applicable, that are applicable to such transaction). The Participant's election shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate. If the Participant fails to make an election, the Company will withhold Shares having a fair market value equal to the minimum statutory withholding that may be imposed on the transaction, as provided above. For purposes of tax withholding pursuant to this Section 2.10, unless applicable laws and regulations dictate otherwise, the Company shall determine fair market value based on the closing price of a Share as reported on the New York Stock Exchange or other applicable public market on the business day immediately preceding the applicable RSU Settlement Date.

2.11 Compliance with Section 409A of the Code. Notwithstanding any provision in this Agreement to the contrary, to the extent that this Agreement constitutes a nonqualified deferred compensation plan or arrangement to which Section 409A of the Code applies, the administration of this Award (including the time and manner of payments under the Award and this Agreement) shall comply with Section 409A of the Code. In connection therewith, any settlement or payment to the Participant with respect to the Award under this Agreement which Section 409A(a)(2)(B)(i) of the Code indicates may not be made before the date which is six months after third Trading Day following the date of public disclosure of the Participant's separation from employment service (the " financial results for a particular fiscal quarter or year and continuing until the close of market on the 10Section 409A Six-Month Waiting Period th calendar day prior to the end of each fiscal quarter or year ("**Trading Window**"), as .

The prohibition against trading during the Blackout Period encompasses the fulfillment of standing or limit orders, margin sales, or any other transactions providing instruction or discretion to any broker to execute transactions, and the brokers with whom such orders are placed must be so instructed at the time it is placed.

The prohibition against trading during the Blackout Period does not apply to transactions (a) involving Company withholding of shares subject to the vesting of an award in order to satisfy tax withholding requirements (however, a result of change in the fact that the Participant is a specified key employee referred election to in Section 409A(a)(2)(B)(i) of the Code, shall not occur withhold shares or pay cash to satisfy withholding under awards must be made during a Trading Window); (b) involving the Section 409A Six-Month Waiting Period but rather shall purchase of stock through a Company employee stock purchase plan, if any (however, any shares so acquired must be delayed, if such settlement or payment would otherwise occur during the Section 409A Six-Month Waiting Period, held until the expiration of the Section 409A Six-Month Waiting Period. Except as provided under Section 1.2(a), the Participant will not be considered to have a termination of employment Blackout Period has expired); or separation from employment under this Agreement unless the termination of employment or separation from employment constitutes a "separation from service" under Treasury Regulation Section 1.409A-1(h).

2.12 Personal Data. The Participant hereby consents to the collection, use, and transfer, in electronic or other form, of the Participant's Personal Data by and among, as applicable, the Company and its affiliates for the exclusive purpose of implementing, administering, and managing the Participant's participation in the (c) effected through an approved Rule 10b5-1 Plan. The Company holds, Blackout Period does apply, however, to any sale of stock as part of a broker-assisted cashless exercise of an option or may receive from any agent designated by the Company, certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social security insurance number or other identification number, salary, nationality, job title, any shares of Common Stock held, details of this Award and any other rights to shares of Common Stock awarded, canceled, exercised, vested, unvested, or outstanding in the Participant's favor, market sale for the purpose of implementing, administering, generating the cash needed to pay the exercise price of an option.

2. *Event Specific Restrictions.* From time to time, the Company may also prohibit the Window Group and/or other insiders from trading in Company Securities, even during a Trading Window, because of developments known to the Company and managing not yet disclosed to the Plan, including complying with applicable tax public. In this event, the Window Group and/or other insiders may not engage in any transaction involving Company Securities until advised by the Company in writing that trading is no longer suspended, and securities laws (the "***Personal Data***"). The Personal Data may be transferred must not disclose to any third parties others the fact of the trading suspension.

assisting It should be noted that even during the Trading Window, any person aware of material nonpublic information concerning the Company should not engage in any transactions in Company Securities until the information has been known publicly for at least two full Trading Days, whether or not the Company has recommended a suspension of trading to that person. Trading in Company Securities during the Trading Window should not be considered a “safe harbor,” and all insiders should use good judgment at all times.

B. Pre-Clearance of Trades

To help prevent inadvertent violations of the federal securities laws and to avoid even the appearance of trading on the basis of material nonpublic information, members of the Window Group may not transact in Company Securities (including open market purchases or the making of bona fide gifts), even during a Trading Window, without first complying with the Company’s “pre-clearance” process. Prior to commencing any transaction, each member of the Window Group shall complete and submit a Securities Transaction Authorization Form (a copy of which is attached as Annex B hereto) to the Office of the General Counsel, describing the nature of the proposed transaction, providing the type and number of

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securities subject thereto, confirming such individual is not in possession of material nonpublic information, and providing certain additional requested information. A request for pre-clearance should be submitted to the Office of the General Counsel at least two business days in advance of the proposed transaction, unless earlier notice is otherwise required by the Policy. The General Counsel may consult with the Company’s Chief Executive Officer or Chief Financial Officer before any proposed trade is cleared by the Company. Once clearance is received from the Company, the member of the Window Group that requested clearance of the trade must initiate the transaction within the time period set forth in the implementation, administration, and management Securities Transaction Authorization Form, or repeat the pre-clearance process.

Notwithstanding the pre-clearance of the Plan. The Participant authorizes such recipients of the Personal Data to receive, possess, use, retain, and transfer the Personal Data, in electronic or other form, for the purposes described above, and the Participant hereby releases any proposed trade by the Company, and its affiliates from no person subject to this Addendum may engage in a trade while in possession of material nonpublic information (other than transactions effected through an approved Rule 10b5-1 Plan or transactions described under the heading “Transactions under Company Plans” in the Policy). In addition, the Company’s General Counsel may revoke any of the Participant’s claims related to the use or disclosure of such Personal Data. The Participant may, pre-clearance at any time view before a pre-cleared transaction is initiated, and the Personal Data, request additional information about the storage and processing member of the Personal Data, require Window Group shall immediately take all steps reasonably required to terminate any pending trade.

II. Additional Information for Directors and Officers

The Company’s directors, Section 16 officers (as defined below), and 10% owners are required to file reports on Forms 3, 4 and 5, as appropriate, under Section 16(a) of the Exchange Act with the SEC when they engage in transactions in Company Securities. Although the Company may generally assist its directors and Section 16 officers in preparing and filing the required reports, directors and Section 16 officers retain responsibility for such reports. Directors and Section 16 officers are encouraged to engage a knowledgeable broker to assist in providing the Office of the General Counsel with all necessary amendments to transaction information for timely preparation of Section 16 reports and filings under Rule 144, as applicable.

“**Section 16 officer**” means the Personal Data, or refuse or withdraw Company’s president, principal financial officer, principal accounting officer (or if none, the consents herein, in controller) any case without cost, by contacting the Corporate Secretary vice-president of the Company in writing. Any such refusal charge of a principal business unit, division or withdrawal function (such as sales, administration or finance), and any other officer who performs a policy-making function, as determined from time to time by the Board, or any other person who performs similar policy-making functions for the Company, as determined from time to time by the Board. Officers of the consents herein may affect Company’s subsidiaries shall also be deemed officers of the Participant’s ability Company if they perform policy-making functions for the Company, as determined from time to participate in the Plan.

2.13 Electronic Delivery of Documents. The Company may, in its sole discretion, deliver any documents related to this Award, or any future awards that may be granted under the Plan, by electronic means, or request the Participant’s consent to participate in the Plan or other authorizations from the Participant in connection therewith by electronic means. The Participant hereby consents to receive such documents by electronic delivery and, if requested, to participate in the Plan through an on-line or electronic system established and maintained time by the Company or another third party designated by the Company. Board.

2.14 A. Receipt Power of Award and Related Documents. The Participant hereby acknowledges the receipt, either directly or electronically, of the Award, a copy of the Plan, and a prospectus for the Plan. Attorney.

2.15 Attached as Execution Annex C is a model power of attorney that would give the Company’s General Counsel and Counterparts. This Agreement may be executed in counterparts. Execution of this Agreement may be evidenced by any appropriate form of electronic signature or affirmative email or certain other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication specified representatives of the intention by such party Company the authority to execute or adopt such instrument for purposes sign Forms 3, 4 and 5 on your behalf in your absence. Please sign the power of execution hereof. attorney and provide it to the Company’s General Counsel at your earliest opportunity.

* * * * * *B. Notifying the Company’s General Counsel of Transactions.*

[Signature page follows] Prior to engaging in any transaction involving Company Securities (including open market purchases and bona fide gifts), members of the Window Group must obtain written pre-approval from the Company’s General Counsel and Chief Executive Officer or Chief Financial Officer by completing the Securities Transaction Authorization Form. Following completion of any transaction in Company Securities, directors and Section 16 Officers must immediately notify the Office of the General Counsel of the details of the transaction(s) and provide copies of any broker confirmations or related documentation, in order to enable compliance with applicable securities laws provisions.

C. Short-Swing Profit Provisions.

Directors, Section 16 Officers and 10% owners of the Company's common stock are liable to the Company for any "short-swing profits" resulting from any combination of purchase and sale, or sale and purchase, of Company Securities within a period of less than six months. Insiders are encouraged to engage a knowledgeable broker and contact the Office of the General Counsel concerning any questions related to short-swing profits.

Addendum Page 2

ANNEX A TO ADDENDUM TO
SECURITIES TRADING POLICY

WINDOW GROUP CERTIFICATION

By my signature below, I acknowledge and agree that (a) the Company has notified me that I am an insider identified by the Company as a member of the Window Group (as defined in the Addendum); (b) I will remain a member of the Window Group until notified otherwise in writing by the Company's General Counsel; and (c) as a member of the Window Group: (1) I am prohibited from any trading in Company Securities during the Blackout Period (as defined in the Addendum) or any event specific restriction; and (2) all trades by me or for my account in Company Securities are subject to the pre-clearance process set forth in Section I.B. of the Addendum.

____
Signature

____
Type or Print Name

____
Date

ANNEX B TO
ADDENDUM TO
SECURITIES TRADING POLICY

SECURITIES TRANSACTION
AUTHORIZATION FORM

ANNEX C TO

ADDENDUM TO

SECURITIES TRADING POLICY

IN WITNESS WHEREOF, the Company and the Participant have caused this Restricted Stock Unit Award Agreement to be entered into effective as of the Award Date.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By: ____
Printed Name: James B. Lebeck
Title: Senior Vice President and General Counsel
Date Signed: ________________

PARTICIPANT:

Signature: __________________________________
Printed Name: POWER OF ATTORNEY

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EXHIBIT 21.1

SUBSIDIARIES
OF
SM ENERGY COMPANY

None. Pursuant to Securities and Exchange Commission ("SEC") Regulation S-K, Item 601(b)(21), no subsidiaries or aggregation of subsidiaries constitute a significant subsidiary, as defined under SEC Regulation S-X, Rule 1-02(w), as of December 31, 2023 December 31, 2024.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement Statements (Form S-8 Nos. 333-30055, 333-35352, 333-88780, 333-58273, 333-134221, 333-151779, 333-165740, 333-170351, 333-194305, 333-212359, 333-219719, 333-226660, and 333-257005) of SM Energy Company
(2) Post-Effective Amendment No. 1 to Registration Statement (Form S-8 No. 333-106438) of SM Energy Company,
(3) Registration Statement (Form S-3 Nos. 333-257046 and 333-259979) of SM Energy Company;

of our reports dated February 22, 2024 February 20, 2025, with respect to the consolidated financial statements of SM Energy Company and subsidiaries and the effectiveness of internal control over financial reporting of SM Energy Company and subsidiaries, included in this Annual Report (Form 10-K) of SM Energy Company and subsidiaries for the year ended December 31, 2023 December 31, 2024.

/s/ Ernst & Young LLP

Denver, Colorado
February 22, 2024 20, 2025

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EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of SM Energy Company for the year ended December 31, 2023 December 31, 2024. We hereby further consent to the use of information contained in our reports, and the use of our audit letter, as of December 31, 2023 December 31, 2024, relating to estimates of revenues from SM Energy Company's oil, gas, and NGL reserves. We further consent to the incorporation by reference thereof into SM Energy Company's Post-Effective Amendment No. 1 to Registration Statement No. 333-106438 on Form S-8, Registration Statement Nos. 333-30055, 333-35352, 333-88780, 333-58273, 333-134221, 333-151779, 333-165740, 333-170351, 333-194305, 333-212359, 333-219719, 333-226660, and 333-257005 on Form S-8, and Registration Statement Nos. 333-257046 and 333-259979 on Form S-3. S-8.

/s/ RYDER SCOTT COMPANY, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 22, 2024 20, 2025

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EXHIBIT 31.1

CERTIFICATION

I, Herbert S. Vogel, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2024 February 20, 2025

/s/ HERBERT S. VOGEL
Herbert S. Vogel
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, A. Wade Pursell, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2024 February 20, 2025

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION

PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of SM Energy Company (the “Company”) for the fiscal year ended December 31, 2023 December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Herbert S. Vogel, as President and Chief Executive Officer of the Company, and A. Wade Pursell, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ HERBERT S. VOGEL
Herbert S. Vogel
President and Chief Executive Officer
February 22, 2024 20, 2025

/s/ A. WADE PURSELL

A. Wade Pursell
Executive Vice President and Chief Financial Officer
February 22, 2024 20, 2025

EXHIBIT 97.1 95.1

Mine Safety Disclosures

CLAWBACK POLICY
(Adopted as Section 1503(a) of July 27, 2023)

This Clawback Policy (this "***Policy***" the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") has been adopted and Item 104 of Regulation S-K (17 CFR 229.104) ("Item 104") require certain disclosures by SM Energy Company (the "***Company***") companies required to address the recovery of erroneously awarded compensation in compliance with the rules set forth in Section 10D-1 of file periodic reports under the Securities Exchange Act of 1934, as amended, (the "***Exchange*** ***that operate mines regulated under the Federal Mine Safety and Health Act***") of 1977, as amended by the Mine Improvement and the related listing rules New Emergency Response Act of 2006 ("Mine Act").

On October 1, 2024, as part of the New York Stock Exchange (the " Uinta Basin Acquisition, the Company acquired a sand mine that is subject to regulation by the U.S. Federal Mine Safety and Health Administration ("MSHA"). The sand mine is listed under MSHA Mine ID No. 42-02760 and is located in Duchesne County, Utah ("Bundick Sand Mine"). Operations at the Bundick Sand Mine are conducted by a third party.

Mine Safety Information

The following provides additional information about references used in the table below to describe the categories of violations, orders or citations issued by MSHA under the Mine Act:

- *NYSE Section 104(a) Significant and Substantial ("S&S") Citations:*"), specifically including Citations for violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a mine safety or health hazard.
- *Section 303A.14 104(b) Orders*: Orders which represent a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the NYSE Listed Company Manual (collectively, the "***Clawback Rules***"). This Policy supersedes and replaces in its entirety any prior or existing policies adopted mine affected by the Company condition until MSHA determines that the violation has been abated.
- *Section 104(d) Citations and Orders*: Citations and orders for an unwarrantable failure to comply with respect mandatory health or safety standards.
- *Section 110(b) Violations*: Flagrant violations.
- *Section 107(a) Orders*: Orders for situations in which MSHA determined an "imminent danger" (as defined by MSHA) existed.
- *Notice of Pattern of Violations*: Notice of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the clawback cause and effect of compensation payable to a person covered by this Policy. To the extent this Policy is in any manner deemed inconsistent with the Clawback Rules, this Policy shall be treated as retroactively amended to be compliant with such rules.

Certain Definitions

An "***Executive Officer***" is the Company's current mine health or former president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any vice- president safety hazards under section 104(e) of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the executive officers identified pursuant to Item 401(b) of Regulation S-K promulgated under the Exchange Mine Act.

"• *Financial Reporting Measures Notice of Potential Pattern of Violations*" are measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and any measures that are derived wholly or in part from such measures. Stock price and total shareholder return are also Financial Reporting Measures. A Financial Reporting Measure need not be presented within the financial statements: Notice of the Company or included in potential to have a filing made by the Company with the Securities and Exchange Commission (the "***SEC***") pattern of violations under section 104(e).

- *Pending Legal Actions*: Legal actions before the Federal Mine Safety and Health Review Commission initiated.

For the year ended December 31, 2024	
Citation, Order, Violation or Action	Bundick Sand Mine
Section 104(a) *S&S* citations (#) (1)	1
Section 104(b) orders (#)	None
Section 104(d) citations and orders (#)	None
Section 110(b)(2) violations (#)	None
Section 107(a) orders (#)	None
Proposed assessments under MSHA ($)	$204
Mining-related fatalities (#)	None
Notice of pattern of violations (yes/no)	No
Notice of potential pattern of violations (yes/no)	No
Pending legal actions (#)	None

" (1)***Incentive-Based Compensation***" is any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

Incentive-Based Compensation is deemed "***Received***" in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs before or after the end of that period.

Application of the Policy

This Policy shall apply only in the event that the Company is required to prepare an "***accounting restatement***" due to material noncompliance of the Company with any financial reporting requirement under applicable securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period.

Recovery Period

Compensation subject to clawback is Incentive-Based Compensation that is Received by a current or former Executive Officer during the three completed fiscal years immediately preceding the date that the Company is required to prepare an accounting restatement as described under the heading "Application of the Policy," provided that the person served as an Executive Officer at any time during the performance period applicable to the Incentive-Based Compensation in question.

(a) Notwithstanding the foregoing, the Policy shall only apply if the Incentive-Based Compensation is Received by an Executive Officer (1) after such person begins service as an Executive Officer; (2) while the Company has a class of securities listed on the NYSE (or such other national securities exchange on which the Company's securities are then listed), and (3) on or after October 2, 2023.

(b) See Rule 10D-1(b)(1)(i) of the Exchange Act for certain circumstances under which the Policy will apply to Incentive-Based Compensation Received by an Executive Officer during a transition period arising due to a change in the Company's fiscal year.

The date that the Company is required to prepare an accounting restatement shall be determined pursuant to Rule 10D-1(b)(1)(ii) of the Exchange Act, which provides that the date is the earlier to occur of: (a) the date the Board of Directors of the Company (the "***Board***"), a committee of the Board (a "***Committee***"), or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an accounting restatement as described under the heading "Application ofthe Policy"; or (b) the date a court, regulator, or other legally authorized body directs the Company to prepare an accounting restatement.

Erroneously Awarded Compensation

The amount of Incentive-Based Compensation subject to the Policy ("***Erroneously Awarded Compensation***") is the amount of Incentive-Based Compensation Received that exceeds the amount of Incentive Based-Compensation that otherwise would have been Received had it been determined based citation was both issued and terminated on the restated amounts and shall be computed without regard to any taxes paid. For Incentive-Based Compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an accounting restatement: (a) the amount shall be based on a reasonable estimate made by the Board (or, at the discretion of the Board, any Committee that has been delegated such authority by the Board), of the effect of the accounting restatement on the stock price or total shareholder return October 16, 2024.

upon which the Incentive-Based Compensation was Received; and (b) the Company must maintain documentation of the determination of that reasonable estimate and provide such documentation to the NYSE.

Recovery by the Company

The Company shall recover reasonably promptly any Erroneously Awarded Compensation except to the extent that the conditions of paragraphs (a) or (b) below apply. The Board (or any Committee that has been delegated such authority by the Board) shall determine the repayment schedule for each amount of Erroneously Awarded Compensation in a manner that complies with this "reasonably promptly" requirement. Such determination shall be made consistent with any applicable legal guidance, by the SEC, the NYSE, judicial opinion, or otherwise. The determination of what constitutes "reasonably promptly" may vary from case to case and will depend on the particular facts and circumstances applicable to the Company, the accounting restatement and the Erroneously Awarded Compensation, among other factors. The Board (or any Committee that has been delegated such authority by the Board) is authorized to adopt additional rules to further describe what repayment schedules satisfy this requirement.

(a) Erroneously Awarded Compensation need not be recovered if the direct expense paid to a third party to assist in enforcing the Policy would exceed the amount to be recovered and the Board (or any Committee that has been delegated such authority by the Board) has made a determination that recovery would be impracticable. Before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation based on expense of enforcement, the Company shall make a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to recover, and provide that documentation to the NYSE.

(b) Erroneously Awarded Compensation need not be recovered if recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

Board Decisions

Decisions of the Board (or any Committee that has been delegated authority by the Board) with respect to this Policy shall be final, conclusive and binding on all Executive Officers subject to this Policy, unless determined to be an abuse of discretion or determined to be unenforceable by the SEC or the NYSE.

No Indemnification

Notwithstanding anything to the contrary in any other policy or governing document of the Company or any agreement between the Company and an Executive Officer, no Executive Officer shall be indemnified by the Company against the loss of any Erroneously Awarded Compensation.

Agreement to Policy by Executive Officers

The Board shall take reasonable steps to inform Executive Officers of this Policy. Executive Officers should read this Policy carefully, ask questions of the Company's Office of the General Counsel, and sign and return the certification attached as **Annex A**. The failure by any current or former Executive Officer to sign and return the certification attached as **Annex A**shall not render this Policy unenforceable.

ANNEX A

CLAWBACK POLICY CERTIFICATION

I have read and understand the Clawback Policy (the "***Policy***") of SM Energy Company (the "***Company***"). I agree that I will comply with the policies and procedures set forth in the Policy. I understand and agree that, if I am an employee of the Company or one of its subsidiaries or other affiliates, my failure to comply in all respects with the Company's policies, including the Policy, is a basis for termination of my employment with the Company and any subsidiary or other affiliate to which my employment now relates or may in the future relate.

I am aware that this signed Certification will be filed with my personnel records in the Company's Human Resources Department.

Signature:

Type or Print Name:

Date:

EXHIBIT 99.1

SM ENERGY COMPANY

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2023 2024

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.

TBPELS License No. 116149

Senior Vice President

/s/ Eric A. Sepolio

Eric A. Sepolio, P.E.

TBPELS License No. 128738

Vice President

RYDER SCOTT COMPANY, L.P.

TBPELS Firm Registration No. F-1580

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January 10, 2025

January 10, 2024

Mr. Levi J. Briese, P.E. Dennis Zubieta
Corporate Engineering Manager Business Development Director
SM Energy Company
1700 Lincoln Street, Suite 3200

Denver, CO 80203

Dear Mr. Briese: Zubieta,

At the request of SM Energy Company (SM Energy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2023 December 31, 2024 prepared by SM Energy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations).Our reserves audit, completed on January 3, 2024 January 8, 2025 and presented herein, was prepared for public disclosure by SM Energy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent SM Energy's estimated net reserves attributable to the leasehold interests in certain properties owned by SM Energy and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2023 December 31, 2024.The properties reviewed by Ryder Scott incorporate SM Energy reserves determinations and are located in the state states of Texas. Texas and Utah.

The properties reviewed by Ryder Scott account for a portion of SM Energy's total net proved liquid hydrocarbon and gas reserves as of December 31, 2023 December 31, 2024.Based on the estimates of total net proved reserves prepared by SM Energy, the reserves audit conducted by Ryder Scott addresses approximately 86 85 percent of the total proved net reserves of SM Energy on a barrel of oil equivalent, BOE basis as of December 31, 2023 December 31, 2024.

The properties reviewed by Ryder Scott account for a portion of SM Energy's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2023 December 31, 2024.Based on the reserves and income projections prepared by SM Energy, the audit conducted by Ryder Scott addresses approximately 92 91 percent of the total proved discounted future net income at 10% of SM Energy as of December 31, 2023 December 31, 2024.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as “the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and

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633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information.” Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2023 December 31, 2024 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. SM Energy has informed us that in the preparation of their reserves and income projections, as of December 31, 2023 December 31, 2024, they used average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by SM Energy attributable to SM Energy's interest in properties that we reviewed and for those that we did not review are summarized as follows:

SEC PARAMETERS Estim N Rese

	As of December 31, 2023									
As of December 31, 2024						As of December 31, 2024				
		Proved*					Proved			
		Developed			Total		Developed			Total
		Producing	Non-Producing	Undeveloped	Proved		Producing	Non-Producing	Undeveloped	Proved
Audited by Ryder Scott										
Net Reserves										
Audited by Ryder Scott						***Audited by Ryder Scott***				
Net Reserves						***Net Reserves***				
Oil/Condensate – MBBLS	Oil/Condensate – MBBLS	114,083	2	85,513	199,598	Oil/Condensate – MBBLS	147,633	0	104,508	252,141
Plant Products – MBBLS	Plant Products – MBBLS	61,601	93	42,029	103,723	Plant Products – MBBLS	65,369	0	39,923	105,292
Gas – MMCF	Gas – MMCF	921,074	914	394,399	1,316,387	Gas – MMCF	977,109	0	354,109	1,331,218
MBOE	MBOE	329,196	247	193,276	522,719	MBOE	375,854	0	203,448	579,302
Not Audited by Ryder Scott										
Net Reserves										

Not Audited by Ryder Scott ***Net Reserves***						***Not Audited by Ryder Scott*** ***Net Reserves***				
Oil/Condensate – MBBLS	Oil/Condensate – MBBLS	2,486	1,923	26,069	30,478	Oil/Condensate – MBBLS	11,410	1,295	31,174	43,879
Plant Products – MBBLS	Plant Products – MBBLS	360	2,598	12,773	15,731	Plant Products – MBBLS	2,655	3,745	12,437	18,837
Gas – MMCF	Gas – MMCF	8,792	17,690	189,087	215,569	Gas – MMCF	29,200	24,980	163,723	217,903
MBOE	MBOE	4,311	7,469	70,357	82,137	MBOE	18,932	9,203	70,898	99,033
Total Net Reserves	***Total Net Reserves***					***Total Net Reserves***				
Oil/Condensate – MBBLS	Oil/Condensate – MBBLS	116,569	1,924	111,582	230,076	Oil/Condensate – MBBLS	159,043	1,295	135,682	296,020
Plant Products – MBBLS	Plant Products – MBBLS	61,960	2,690	54,803	119,454	Plant Products – MBBLS	68,024	3,745	52,360	124,129
Gas – MMCF	Gas – MMCF	929,867	18,604	583,485	1,531,956	Gas – MMCF	1,006,309	24,980	517,832	1,549,121
MBOE	MBOE	333,507	7,714	263,633	604,856	MBOE	394,785	9,203	274,347	678,335

** Certain summaries and calculations may vary due to rounding. The rounding is not material.*

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBLS). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in status category.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At SM Energy's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is

identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable

and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves prepared by SM Energy for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. In general, the reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through November 2023 2024 in those cases where such data were considered to be definitive. The data used in these analyses were furnished to Ryder Scott by SM Energy or obtained from public data sources and were considered sufficient for the purpose thereof. In certain cases, producing reserves were estimated analogy. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate.

The reserves prepared by SM Energy attributable to the non-producing and the undeveloped status categories that we reviewed were estimated by analogy. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates.

Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves

reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by SM Energy relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by SM Energy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of

this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2023 December 31, 2024 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by SM Energy for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by SM Energy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy.

The table below summarizes SM Energy’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as SM Energy’s “average realized prices.” The average realized prices shown in the table below were determined from SM Energy’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and SM Energy’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$78.22/ 75.48/BBL	$77.91/ 74.78/BBL
	NGLs	NGL Basket OPIS Mont Belvieu Non-TET(1)	$27.72/ 28.29/BBL	$22.48/ 22.52/BBL
	Gas	Henry Hub	$2.637/ 2.13/MMBTU	$2.53/ 1.87/MCF

(1)*Price reflects composition of ethane, butanes, and natural gasoline.*

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in SM Energy’s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by SM Energy are based on the operating expense reports of SM Energy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated

directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements**.** The operating costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by SM Energy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. The estimated net cost of abandonment after salvage was included by SM Energy for properties where abandonment costs net of salvage were material. SM Energy's estimates of the net abandonment costs were accepted without independent verification.

The estimated net cost of abandonment after salvage was included by SM Energy for properties where certain abandonment costs net of salvage were provided by SM Energy and for which they requested be included in our report. SM Energy's estimates of the net abandonment costs were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by SM Energy and included herein.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with SM Energy's plans to develop these reserves as of December 31, 2023December 31, 2024. The implementation of SM Energy's development plans as presented to us is subject to the approval process adopted by SM Energy's management. As the result of our inquiries during the course of our review, SM Energy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by SM Energy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SM Energy. SM Energy has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, SM Energy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2023December 31, 2024, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by SM Energy were held constant throughout the life of the properties.

SM Energy's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by SM Energy to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet

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on production, sales were estimated to commence at an anticipated date furnished by SM Energy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in SM Energy's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

SM Energy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which SM Energy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by SM Energy for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of SM Energy are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

SM Energy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of SM Energy's forecast of future proved production, we have relied upon data furnished by SM Energy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SM Energy. The data described herein were accepted as authentic and sufficient for determining the reserves unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. We consider the factual data furnished to us by SM Energy to be appropriate and sufficient for the purpose of our review of SM Energy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by SM Energy and as reviewed by us appropriate for the purpose hereof,

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and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

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Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2023 December 31, 2024 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by SM Energy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with SM Energy's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between SM Energy's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to SM Energy when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by SM Energy.

Other Properties

Other properties, as used herein, are those properties of SM Energy which we did not review. The proved net reserves attributable to the other properties account for approximately 14 15 percent of the total proved net liquid hydrocarbon and gas reserves of SM Energy on a barrel of oil equivalent, BOE basis, based on estimates prepared by SM Energy as of December 31, 2023 December 31, 2024. The other properties represent approximately 8 9 percent of the total proved discounted future net income at 10% based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by SM Energy as of December 31, 2023 December 31, 2024.

The same technical personnel of SM Energy were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

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encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to SM Energy. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by SM Energy.

SM Energy makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SM Energy has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of SM Energy, of the references to our name, as well as to the references to our third party report for SM Energy, which appears in the December 31, 2023 December 31, 2024 annual report on Form 10-K of SM Energy. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SM Energy.

We have provided SM Energy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by SM Energy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Marsha E. Wellmann

Marsha E. Wellmann, P.E.
TBPELS License No. 116149
Senior Vice President

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/s/ Eric A. Sepolio

Eric A. Sepolio, P.E P.E.
TBPELS License No. 128738
Vice President

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MEW-EAS (LPC) (HGA)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Ms. Marsha E. Wellmann was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Ms. Wellmann, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2012, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America and the Gulf of Mexico. Before joining Ryder Scott, Ms. Wellmann served in a number of engineering positions. For more information regarding Ms. Wellmann geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Ms. Wellmann earned a Bachelor of Science degree in Petroleum Engineering and a Business Foundations Certificate from The University of Texas at Austin in 2002 and is a registered Professional Engineer in the State of Texas. She is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Ms. Wellmann fulfills. As part of her 2023 2024 continuing education hours, Ms. Wellmann attended 34 29 hours of formalized training including various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on her educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Ms. Wellmann has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

DISCLAIMER