UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2023

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

For the transition period from ____________ to____________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**95-3848122**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

4350 Baker Road – Suite 400
Minnetonka, Minnesota 55343
(Address of Principal Executive Offices)

(952) 476-9800
(Registrant's Telephone Number, Including Area Code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.001	NOG	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller Reporting Company ☐
	Emerging Growth Company ☐

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

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

As of October 31, 2023, there were 100,507,638 shares of our common stock, par value $0.001, outstanding.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of crude oil and natural gas:

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"*Boe*." A barrel of oil equivalent and is a standard convention used to express crude oil, NGL and natural gas volumes on a comparable crude oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or NGL.

"*Boepd*." Boe per day.

"*Btu" or "British Thermal Unit*." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand Boe.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate or NGLs.

"*MMBoe*." One million Boe.

"*MMBtu*." One million British Thermal Units.

"*MMcf*." One million cubic feet of natural gas.

"*NGLs*." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

"*Basin*." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion.*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"*Conventional play.*" An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"*Developed acreage.*" Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Development well.*" A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential.*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"*Dry hole.*" A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*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 natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"*Extension well*." An extension well is a well drilled to extend the limits of a known reservoir.

"*Field.*" An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*." A layer of rock which has distinct characteristics that differs from nearby rock.

"*Gross acres" or "Gross wells.*" The total acres or wells, as the case may be, in which a working interest is owned.

"*Held by operations.*" A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"*Held by production.*" A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"*Hydraulic fracturing*." The technique of improving a well's production by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"*Infill well.*" A subsequent well drilled in an established spacing unit of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Net acres.*" The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"*Net well.*" A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"*NYMEX*." The New York Mercantile Exchange.

"*OPEC.*" The Organization of Petroleum Exporting Countries.

"*Productive well*." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Recompletion.*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Reservoir.*" A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Service well." A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"*Spacing*." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Stratigraphic test well.*" A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

"*Unconventional play.*" An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

"*Undeveloped acreage*." Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"*Unit*." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*West Texas Intermediate or WTI*." A light, sweet blend of oil produced from the fields in West Texas.

"*Working interest*." The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"Workover." Operations on a producing well to restore or increase production.

Terms used to assign a present value to or to classify our reserves:

"*Developed Oil and Gas Reserves.*" Oil and natural gas reserves of any category that can be expected to be recovered 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.

"*Possible reserves.*" The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"*Pre-tax PV-10%" or "PV-10.*" The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"*Probable reserves.*" The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"*Proved developed non-producing reserves (PDNPs).*" Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"*Proved developed producing reserves (PDPs).*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"*Proved reserves*." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences 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 crude oil, NGLs or natural 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 as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil 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 during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"*Proved undeveloped drilling location.*" A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*." 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 development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not 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 tests in the area and in the same reservoir or an analogous reservoir.

"Reserves." 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.

"*Standardized measure*." Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Undeveloped Oil and Gas Reserves.*" Oil and natural gas 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.

NORTHERN OIL AND GAS, INC.
FORM 10-Q

September 30, 2023

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. ***Condensed Financial Statements.***

NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS

(In thousands, except par value and share data)	September 30, 2023	December 31, 2022
Assets	(Unaudited)	
Current Assets:		
Cash and Cash Equivalents	$ 12,952	$ 2,528
Accounts Receivable, Net	363,516	271,336
Advances to Operators	25,431	8,976
Prepaid Expenses and Other	2,567	2,014
Derivative Instruments	65,160	35,293
Income Tax Receivable	—	338
Total Current Assets	469,626	320,485
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	8,135,649	6,492,683
Unproved	36,827	41,565
Other Property and Equipment	7,421	6,858
Total Property and Equipment	8,179,897	6,541,106
Less – Accumulated Depreciation, Depletion and Impairment	(4,391,261)	(4,058,180)
Total Property and Equipment, Net	3,788,636	2,482,926
Derivative Instruments	29,543	12,547
Acquisition Deposit	—	43,000
Other Noncurrent Assets, Net	16,861	16,220
Total Assets	$ 4,304,666	$ 2,875,178
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts Payable	$ 235,129	$ 128,582
Accrued Liabilities	154,882	121,737
Accrued Interest	32,074	24,347
Income Tax Payable	2,051	—
Derivative Instruments	176,339	58,418
Contingent Consideration	—	10,107
Other Current Liabilities	2,016	1,781
Total Current Liabilities	602,491	344,972
Long-term Debt, Net	2,057,359	1,525,413
Deferred Tax Liability	7,291	—
Derivative Instruments	190,086	225,905
Asset Retirement Obligations	36,799	31,582
Other Noncurrent Liabilities	2,847	2,045
Total Liabilities	$ 2,896,873	$ 2,129,917
Commitments and Contingencies		

Stockholders' Equity		
Common Stock, Par Value $.001; 135,000,000 Shares Authorized; 93,032,638 Shares Outstanding at 9/30/2023 85,165,807 Shares Outstanding at 12/31/2022	495	487
Additional Paid-In Capital	1,873,940	1,745,532
Retained Deficit	(466,642)	(1,000,759)
Total Stockholders' Equity	1,407,793	745,260
Total Liabilities and Stockholders' Equity	$ 4,304,666	$ 2,875,178

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
(UNAUDITED)

(In thousands, except share and per share data)	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Revenues				
Oil and Gas Sales	$ 511,651	$ 534,050	$ 1,354,376	$ 1,540,151
Gain (Loss) on Commodity Derivatives, Net	(199,548)	257,590	11,878	(339,995)
Other Revenues	1,870	—	6,488	—
Total Revenues	313,973	791,640	1,372,742	1,200,156
Operating Expenses				
Production Expenses	82,506	68,478	244,944	187,659
Production Taxes	42,158	42,273	114,215	120,729
General and Administrative Expenses	11,846	10,278	37,248	32,155
Depletion, Depreciation, Amortization and Accretion	133,791	65,975	334,836	173,956
Other Expenses	1,234	—	3,681	—
Total Operating Expenses	271,535	187,004	734,924	514,499
Income From Operations	42,438	604,637	637,818	685,658
Other Income (Expense)				
Interest Expense, Net of Capitalization	(37,040)	(20,135)	(99,151)	(56,523)
Gain (Loss) on Unsettled Interest Rate Derivatives, Net	—	(42)	(1,017)	1,772
Gain on Extinguishment of Debt, Net	—	339	659	574
Contingent Consideration Gain	—	—	10,107	—
Other Income (Expense)	21	(1)	4,712	(184)
Total Other Income (Expense)	(37,019)	(19,839)	(84,690)	(54,361)
Income Before Income Taxes	5,419	584,798	553,128	631,296
Income Tax Expense (Benefit)	(20,691)	1,333	19,012	3,128
Net Income	$ 26,111	$ 583,465	$ 534,116	$ 628,169
Cumulative Preferred Stock Dividend	—	(2,610)	—	(8,437)
Premium on Repurchase of Preferred Stock	—	—	—	(25,320)
Net Income Attributable to Common Stockholders	$ 26,111	$ 580,855	$ 534,116	$ 594,412
Net Income Per Common Share – Basic	$ 0.28	$ 7.39	$ 6.01	$ 7.66
Net Income Per Common Share – Diluted	$ 0.28	$ 6.77	$ 5.97	$ 6.92
Weighted Average Common Shares Outstanding – Basic	92,768,035	78,589,661	88,857,016	77,632,410
Weighted Average Common Shares Outstanding – Diluted	93,742,407	86,141,293	89,449,731	87,056,158

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
(UNAUDITED)

(In thousands)	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Cash Flows from Operating Activities		
Net Income	$ 534,116	$ 628,169
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization, and Accretion	334,836	173,956
Amortization of Debt Issuance Costs	5,824	3,316
Gain on Extinguishment of Debt	(659)	(574)
Amortization of Bond Premium/Discount on Long-term Debt	(1,188)	(1,599)
Deferred Income Taxes	18,121	805
Unrealized (Gain) Loss of Derivative Instruments	35,239	(54,163)
Gain on Contingent Consideration	(10,107)	—
Loss on Disposal of Fixed Assets	—	185
Stock-Based Compensation Expense	4,479	4,209
Other	2,882	2,165
Changes in Working Capital and Other Items:		
Accounts Receivable, Net	(91,588)	(121,904)
Prepaid and Other Expenses	(553)	(1,000)
Accounts Payable	531	15,997
Accrued Interest	7,484	(14,154)
Accrued Liabilities and Expenses	1,542	5,631
Net Cash Provided by Operating Activities	840,959	641,039
Cash Flows from Investing Activities		
Capital Expenditures on Oil and Natural Gas Properties	(1,483,639)	(825,462)
Acquisition Deposit	—	(28,500)
Purchases of Other Property and Equipment	(564)	(4,580)
Net Cash Used for Investing Activities	(1,484,203)	(858,542)
Cash Flows from Financing Activities		
Advances on Revolving Credit Facility	903,000	830,000
Repayments on Revolving Credit Facility	(838,000)	(444,000)
Repurchase of Senior Notes Due 2028	(18,436)	(19,832)
Issuance of Senior Notes Due 2031	492,840	—
Debt Issuance Costs Paid	(11,103)	(6,238)
Issuance of Common Stock	224,682	—
Repurchases of Common Stock	(8,004)	(21,500)
Repurchases of Preferred Stock	—	(81,236)
Restricted Stock Surrenders - Tax Obligations	(2,616)	(2,206)
Preferred Dividends Paid	—	(5,911)
Common Dividends Paid	(88,695)	(31,966)
Net Cash Provided by Financing Activities	653,668	217,112
Net Increase (Decrease) in Cash and Cash Equivalents	10,424	(390)
Cash and Cash Equivalents - Beginning of Period	2,528	9,519
Cash and Cash Equivalents - End of Period	12,952	9,129

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

NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF STOCKHOLDERS' EQUITY
(UNAUDITED)

(In thousands, except share data)	Common Stock		Preferred Stock		Additional Paid-In	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	(Deficit)	(Deficit)
December 31, 2022	85,165,807	$ 487	—	$ —	$ 1,745,532	$ (1,000,759)	$ 745,260
Issuance of Common Stock	193,293	—	—	—	—	—	—
Restricted Stock Forfeitures	(6,854)	—	—	—	(54)	—	(54)
Share Based Compensation	—	—	—	—	2,316	—	2,316
Restricted Stock Surrenders - Tax Obligations	(98,052)	—	—	—	(2,616)	—	(2,616)
Issuance of Common Stock in Exchange for Warrants	403,780	—	—	—	—	—	—
Repurchases of Common Stock	(287,751)	—	—	—	(8,004)	—	(8,004)
Common Stock Dividends Declared	—	—	—	—	(29,026)	—	(29,026)
Net Income	—	—	—	—	—	340,191	340,191
March 31, 2023	85,370,223	$ 487	—	$ —	$ 1,708,147	$ (660,568)	$ 1,048,067
Issuance of Common Stock	11,585	—	—	—	—	—	—
Restricted Stock Forfeitures	(6,550)	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,207	—	1,207
Equity Offerings, Net of Issuance Costs	7,647,500	8	—	—	224,674	—	224,682
Common Stock Dividends Declared	—	—	—	—	(34,414)	—	(34,414)
Deferred Taxes Related to Capped Calls	—	—	—	—	8,441	—	8,441
Net Income	—	—	—	—		167,815	167,815
June 30, 2023	93,022,758	$ 495	—	$ —	$ 1,908,055	$ (492,753)	$ 1,415,797
Issuance of Common Stock	9,880	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,234	—	1,234
Common Stock Dividends Declared	—	—	—	—	(35,349)	—	(35,349)
Net Income	—	—	—	—	—	26,111	26,111
September 30, 2023	93,032,638	$ 495	—	$ —	$ 1,873,940	$ (466,642)	$ 1,407,793

(In thousands, except share data)	Common Stock		Preferred Stock		Additional Paid-In	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Capital	(Deficit)	(Deficit)
December 31, 2021	77,341,921	$ 479	2,218,732	$ 2	$ 1,988,649	$ (1,773,996)	$ 215,135
Issuance of Common Stock	15,651	—	—	—	—	—	—
Restricted Stock Forfeitures	(1,815)	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,499	—	1,499
Restricted Stock Surrenders - Tax Obligations	(89,620)	—	—	—	(2,206)	—	(2,206)
Issuance of Common Stock Warrants - Acquisitions of Oil and Natural Gas Properties	—	—	—	—	17,870	—	17,870
Repurchases of Preferred Stock	—	—	(362,671)	—	(50,225)	—	(50,225)
Common Stock Dividends Declared	—	—	—	—	(10,815)	—	(10,815)
Net Loss	—	—	—	—	—	(206,560)	(206,560)
March 31, 2022	77,266,137	$ 479	1,856,061	$ 2	$ 1,944,773	$ (1,980,556)	$ (35,302)
Issuance of Common Stock	81,948	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,490	—	1,490
Issuance of Common Stock in Exchange for Warrants	2,322,690	2	—	—	(2)	—	—
Repurchases of Common Stock	(447,051)	—	—	—	(12,808)	—	(12,809)
Repurchases of Preferred Stock	—	—	(212,329)	—	(31,011)	—	(31,011)
Preferred Stock Dividends	—	—	—	—	(5,911)	—	(5,911)
Common Stock Dividends Declared	—	—	—	—	(15,071)	—	(15,071)
Net Income	—	—	—	—	—	251,264	251,264
June 30, 2022	79,223,724	$ 481	1,643,732	$ 2	$ 1,881,459	$ (1,729,292)	$ 152,650
Issuance of Common Stock	14,544	—	—	—	—	—	—
Restricted Stock Forfeitures	(200)	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,389	—	1,389
Repurchases of Common Stock	(358,868)	—	—	—	(8,691)	—	(8,691)
Common Stock Dividends Declared	—	—	—	—	(19,716)	—	(19,716)
Net Income	—	—	—	—	—	583,465	583,465
September 30, 2022	78,879,200	$ 481	1,643,732	$ 2	$ 1,854,441	$ (1,145,827)	$ 709,097

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

NOTES TO CONDENSED FINANCIAL STATEMENTS
SEPTEMBER 30, 2023
(UNAUDITED)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "Northern," "our" and words of similar import), a Delaware corporation, is an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company's common stock trades on the New York Stock Exchange under the symbol "NOG".

The Company's principal business is crude oil and natural gas exploration, development, and production with operations in the United States. The Company's primary strategy is investing in non-operated minority working and mineral interests in oil and gas properties in the United States.

NOTE 2 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The financial information included herein is unaudited. The balance sheet as of December 31, 2022 has been derived from the Company's audited financial statements for the year ended December 31, 2022. However, such information includes all adjustments (consisting of normal recurring adjustments) that are, in the opinion of management, necessary for a fair presentation of financial position, results of operations and cash flows for the interim periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for an entire year.

Certain information, accounting policies, and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The condensed financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2022, which were included in the Company's 2022 Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The most significant estimates relate to proved crude oil and natural gas reserves, which includes limited control over future development plans as a non-operator, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of contingent consideration, acquisition date fair values of assets acquired and liabilities assumed, impairment of crude oil and natural gas properties, asset retirement obligations and deferred income taxes.

Management's estimates and assumptions were based on historical data and consideration of future market conditions. Given the uncertainty inherent in any projection, actual results may differ from the estimates and assumptions used, and conditions may change, which could materially affect amounts reported in the unaudited condensed financial statements.

Adopted and Recently Issued Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB") that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

Revenue Recognition

The Company's revenues are primarily derived from its interests in the sale of oil and natural gas production. The Company recognizes revenue from its interests in the sales of crude oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of the product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and natural gas are made under contracts which the third-party operators of the wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in trade receivables, net in the balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption, which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company's oil is typically sold at delivery points under contract terms that are common in our industry. The Company's natural gas produced is delivered by the well operators to various purchasers at agreed upon delivery points under a limited number of contract types that are also common in our industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators will remit payment to the Company for its share in the value of the oil and natural gas sold.

A wellhead imbalance liability equal to the Company's share is recorded to the extent that the Company's well operators have sold volumes in excess of its share of remaining reserves in an underlying property. However, for the three and nine months ended September 30, 2023 and 2022, the Company's natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

The Company's disaggregated revenue has two primary sources: oil sales and natural gas and NGL sales. Substantially all of the Company's oil and natural gas sales come from three geographic areas in the United States: the Williston Basin (North Dakota and Montana), the Appalachian Basin (Pennsylvania), and the Permian Basin (New Mexico and Texas). The following tables present the disaggregation of the Company's oil revenues and natural gas and NGL revenues by basin for the three and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30, 2023				Three Months Ended September 30, 2022			
(In thousands)	**Williston**	**Permian**	**Appalachian**	**Total**	**Williston**	**Permian**	**Appalachian**	**Total**
Oil Revenues	$ 249,276	$ 215,517	$ —	$ 464,793	$ 262,566	$ 113,166	$ —	$ 375,732
Natural Gas and NGL Revenues	17,901	25,214	3,742	46,857	75,036	38,320	44,962	158,318
Other	—	1,870	—	1,870	—	—	—	—
Total	$ 267,177	$ 242,601	$ 3,742	$ 513,520	$ 337,602	$ 151,486	$ 44,962	$ 534,050

	Nine Months Ended September 30, 2023				Nine Months Ended September 30, 2022			
(In thousands)	**Williston**	**Permian**	**Appalachian**	**Total**	**Williston**	**Permian**	**Appalachian**	**Total**
Oil Revenues	$ 683,789	$ 490,217	$ —	$ 1,174,006	$ 826,483	$ 301,956	$ —	$ 1,128,439
Natural Gas and NGL Revenues	83,277	71,681	25,412	180,370	209,969	94,302	107,441	411,712
Other	—	6,488	—	6,488	—	—	—	—
Total	$ 767,066	$ 568,386	$ 25,412	$ 1,360,864	$ 1,036,452	$ 396,258	$ 107,441	$ 1,540,151

Concentrations of Market, Credit Risk and Other Risks

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company's receivables include amounts due, indirectly via the third-party operators of the wells, from purchasers of its crude oil and natural gas production. While certain of these customers, as well as third-party operators of the wells, are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations have been immaterial.

As a non-operator, 100% of the Company's wells are operated by third-party operating partners. As a result, the Company is highly dependent on the success of these third-party operators. If they are not successful in the development, exploitation, production and exploration activities relating to the Company's leasehold interests, or are unable or unwilling to perform, the Company's financial condition and results of operation could be adversely affected. These risks are heightened in a low commodity price environment, which may present significant challenges to these third-party operators. The Company's third-party operators will make decisions in connection with their operations that may not be in the Company's best interests, and the Company may have little or no ability to exercise influence over the operational decisions of its third-party operators. For the three and nine months ended September 30, 2023, the Company's top four operators made up 41% and 40% of total oil and natural gas sales, compared to37% and 40% and for the three and nine months ended September 30, 2022.

The Company faces concentration risk due to the fact that substantially all of its oil and natural gas revenue is sourced from a limited number of geographic areas of operations. As a result, the Company is disproportionately exposed to risks that affect one of more of those areas in North Dakota, Montana, Texas, New Mexico and Pennsylvania.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its counterparties is generally high. In the normal course of business, letters of credit or parent guarantees may be required for counterparties which management perceives to have a higher credit risk.

Net Income (Loss) Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income (loss) attributable to common stockholders (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include shares issuable upon exercise of stock options or warrants and vesting of restricted stock awards, and shares issuable upon conversion of the Series A Preferred Stock (as defined below) or Convertible Notes (see Note 4). The number of potential common shares outstanding are calculated using the treasury stock or if-converted method.

In those reporting periods in which the Company has reported net income available to common stockholders, anti-dilutive shares generally are comprised of the restricted stock that has average unrecognized stock compensation expense greater than the average stock price. In those reporting periods in which the Company has a net loss, anti-dilutive shares are comprised of the impact of those number of shares that would have been dilutive had the Company had net income plus the number of common stock equivalents that would be anti-dilutive had the company had net income.

Restricted stock awards are excluded from the calculation of basic weighted average common shares outstanding until they vest. For restricted stock awards that vest based on achievement of performance and/or market conditions, the number of contingently issuable common shares included in diluted weighted-average common shares outstanding is based on the number of common shares, if any, that would be issuable under the terms of the arrangement if the end of the reporting period were the end of the contingency period, assuming the result would be dilutive.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and nine months ended September 30, 2023 and 2022 are as follows:

(In thousands, except share and per share data)	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Net Income	$ 26,111	$ 583,465	$ 534,116	$ 628,169
Less: Cumulative Dividends on Preferred Stock	—	(2,610)	—	(8,437)
Less: Premium on Repurchase of Preferred Stock	—	—	$ —	$ (25,320)
Net Income Attributable to Common Stockholders	26,111	$ 580,855	$ 534,116	$ 594,412
Weighted Average Common Shares Outstanding:				
Weighted Average Common Shares Outstanding – Basic	92,768,035	78,589,661	88,857,016	77,632,410
Plus: Dilutive Effect of Restricted Stock and Warrants	539,429	7,551,632	446,141	9,423,748
Plus: Dilutive Effect of Convertible Notes	434,944	—	146,574	—
Weighted Average Common Shares Outstanding – Diluted	93,742,407	86,141,293	89,449,731	87,056,158
Net Income per Common Share:				
Basic	$ 0.28	$ 7.39	$ 6.01	$ 7.66
Diluted	$ 0.28	$ 6.77	$ 5.97	$ 6.92

Supplemental Cash Flow Information

The following reflects the Company’s supplemental cash flow information:

(In thousands)	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Supplemental Cash Items:		
Cash Paid During the Period for Interest, Net of Amount Capitalized	$ 94,441	$ 69,015
Cash Paid During the Period for Income Taxes	891	2,322
Non-cash Investing Activities:		
Capital Expenditures on Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities	281,451	164,246
Accrued Liabilities From Acquisitions of Oil and Natural Gas Properties	5,168	—
Capitalized Asset Retirement Obligations	4,019	2,745
Contingent Consideration	—	1,859
Compensation Capitalized on Oil and Gas Properties	223	170
Issuance of Common Stock Warrants - Acquisition of Oil and Natural Gas Properties	—	17,870
Non-cash Financing Activities:		
Issuance of Common Stock Warrants - Acquisitions of Oil and Natural Gas Properties	—	17,870
Issuance of Common Stock in Exchange for Warrants	13,328	76,904
Common Stock Dividends Declared, But Not Paid	35,543	19,787

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The Company follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The Company did not have any impairment of its proved oil and gas properties for the three and nine months ended September 30, 2023 and 2022.

The book value of the Company's crude oil and natural gas properties consists of all acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying condensed statements of operations from the closing date of the acquisition. Acquired assets and liabilities assumed are recorded based on their estimated fair value at the time of the acquisition.

2023 Acquisitions

During the nine months ended September 30, 2023, the Company completed the following larger bolt-on acquisitions (each as defined and described below): the MPDC Acquisition, the Forge Acquisition and the Novo Acquisition (collectively, the "2023 Bolt-on Acquisitions").

In addition to the closing of the 2023 Bolt-on Acquisitions, during the three and nine months ended September 30, 2023, the Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $113.6 million and $172.0 million, respectively.

MPDC Acquisition

On January 5, 2023, the Company completed its acquisition (the "MPDC Acquisition") of certain oil and gas properties, interests and related assets from Midland Petro D.C. Partners, LLC and Collegiate Midstream LLC (collectively, "MPDC"), effective as of August 1, 2022. At closing, the Company acquired a 39.958% working interest in MPDC's four-unit development project in the Permian Midland Basin, which includes an interest in gathering assets associated with the project.

The total consideration at closing was $319.9 million in cash. As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $9.8 million subsequent to closing.

The results of operations from the acquisition from the January 5, 2023 closing date through September 30, 2023, represented approximately $111.3 million of revenue and $74.6 million of income from operations. The Company incurred $3.5 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

	(In thousands)
Fair value of net assets:	
Proved oil and natural gas properties	$ 320,395
Total assets acquired	320,395
Asset retirement obligations	(451)
Net assets acquired	$ 319,944
Fair value of consideration paid for net assets:	
Cash consideration	$ 319,944
Total fair value of consideration transferred	$ 319,944

Forge Acquisition

On June 30, 2023, the Company completed its acquisition (the "Forge Acquisition") of Permian Delaware Basin assets from Forge Energy II Delaware, LLC ("Forge"), effective as of March 1, 2023. At closing, the Company acquired a 30% undivided stake in the assets sold by Forge, with Vital Energy, Inc. acquiring the other 70% and becoming the operator of the assets.

The total consideration at closing, net to the Company, was $167.9 million in cash. As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $0.2 million subsequent to closing.

The results of operations from the acquisition from the June 30, 2023, closing date through September 30, 2023, represented approximately $23.9 million of revenue and $16.3 million of income from operations. The Company incurred $2.4 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	164,925
Unproved oil and natural gas properties		3,892
Total assets acquired		168,817
Asset retirement obligations		(889)
Net assets acquired	$	167,928
Fair value of consideration paid for net assets:		
Cash consideration	$	167,928
Total fair value of consideration transferred	$	167,928

Novo Acquisition

On August 15, 2023, the Company completed its acquisition (the "Novo Acquisition") of certain Permian Delaware Basin assets of Novo Oil & Gas Holdings, LLC ("Novo"), effective as of May 1, 2023. At closing, the Company acquired a 33.33% undivided stake in the assets sold by Novo to Earthstone Energy Holdings, LLC ("Earthstone"), an unaffiliated third party, with Earthstone retaining the other 66.67% and becoming operator of the acquired assets.

The total consideration at closing, net to the Company, was $468.4 million in cash, funded in part by a $37.5 million deposit paid at signing in June 2023.

The results of operations from the acquisition from the August 15, 2023 closing date through September 30, 2023, represented approximately $20.7 million of revenue and $11.1 million of income from operations. The Company incurred $4.5 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	474,417
Total assets acquired		474,417
Asset retirement obligations		(813)
Accrued Liabilities		(5,168)
Net assets acquired	$	468,436
Fair value of consideration paid for net assets:		
Cash consideration	$	468,436
Total fair value of consideration transferred	$	468,436

2022 Acquisitions

During 2022, the Company completed the following larger bolt-on acquisitions (each as defined and described below): the Veritas Acquisition, the Incline Acquisition, the Laredo Acquisition, the Alpha Acquisition, and the Delaware Acquisition (collectively, the "2022 Bolt-on Acquisitions").

During 2022, in addition to the 2022 Bolt-on Acquisitions, the Company acquired oil and natural gas properties through a number of smaller independent transactions for a total of $100.0 million.

Veritas Acquisition

On January 27, 2022, the Company completed the acquisition of certain non-operated oil and gas properties, interests and related assets in the Permian Basin from Veritas TM Resources, LLC, Veritas Permian Resources, LLC, Veritas Lone Star Resources, LLC, and Veritas MOC Resources, LLC, effective as of October 1, 2021 (the "Veritas Acquisition").

The total consideration was $408.8 million, which included $390.9 million in cash and warrants to purchase 1,939,998 shares of the Company's common stock, par value $0.001 per share, at an exercise price equal to $28.30 per share. The warrants had a total estimated fair value of $17.9 million. As a result of customary post-closing adjustments, the Company further decreased its proved oil and natural gas properties and total consideration by $3.0 million subsequent to closing.

The results of operations from the acquisition from the January 27, 2022 closing date through December 31, 2022, represented approximately $244.1 million of revenue and $168.0 million of income from operations. The Company incurred $7.3 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the date of acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	383,755
Unproved oil and natural gas properties		26,262
Total assets acquired		410,017
Asset retirement obligations		(1,219)
Net assets acquired	$	408,798
Fair value of consideration paid for net assets:		
Cash consideration	$	390,928
Issuance of Common Stock Warrants (1.9 million shares at $28.30 per share)		17,870
Total fair value of consideration transferred	$	408,798

Incline Acquisition

On August 15, 2022, the Company completed the acquisition of certain non-operated oil and gas properties, interests and related assets in the Williston Basin from Incline Bakken, LLC, effective as of April 1, 2022 (the "Incline Acquisition").

The total consideration at closing was $159.8 million which includes $158.0 million in cash and $1.8 million in value attributable to potential additional contingent consideration (described in more detail below). As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $6.6 million subsequent to closing.

The results of operations from the acquisition from the August 15, 2022 closing date through December 31, 2022, represented approximately $25.3 million of revenue and $17.0 million of income from operations. The Company incurred $1.1 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	160,155
Total assets acquired		160,155
Asset retirement obligations		(319)
Net assets acquired	$	159,836
Fair value of consideration paid for net assets:		
Cash consideration	$	157,977
Contingent consideration		1,850
Total fair value of consideration transferred	$	159,827

A contingent consideration liability arising from potential additional consideration in connection with the Incline Acquisition was recognized at its fair value. The seller had the potential to earn up to $5.0 million of additional cash consideration dependent upon NYMEX WTI oil pricing at the end of 2022. This contingent consideration was not earned, and there was no remaining associated liability as of December 31, 2022. The acquisition date fair value of the potential additional consideration, totaling $1.8 million, was recorded within contingent consideration liabilities on the Company's balance sheets. Changes in the fair value of the liability (that were not accounted for as revisions of the acquisition date fair value) are recorded in other income (expense) on the Company's statement of operations.

Laredo Acquisition

On October 3, 2022, the Company completed the acquisition of certain non-operated oil and gas properties, interests and related assets in the Permian Midland Basin from Laredo Petroleum, Inc., effective as of August 1, 2022 (the "Laredo Acquisition").

The total consideration at closing was $110.1 million in cash. As a result of customary post-closing adjustments, the Company reduced its proved oil and natural gas properties and total consideration by $3.2 million subsequent to closing.

The results of operations from the acquisition from the October 3, 2022 closing date through December 31, 2022, represented approximately $9.4 million of revenue and $6.8 million of income from operations. The Company incurred $0.8 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	110,258
Total assets acquired		110,258
Asset retirement obligations		(187)
Net assets acquired	$	110,071
Fair value of consideration paid for net assets:		
Cash consideration	$	110,071
Total fair value of consideration transferred	$	110,071

Alpha Acquisition

On December 1, 2022, the Company completed the acquisition of certain non-operated oil and gas properties, interests and related assets in the Permian Delaware Basin from Alpha Energy Partners, effective as of September 1, 2022 (the "Alpha Acquisition").

The total consideration at closing was $164.0 million, which includes $153.9 million in cash and $10.1 million in value attributable to potential additional contingent consideration (described in more detail below). As a result of customary post-closing adjustments, the Company increased its proved oil and natural gas properties and total consideration by $0.3 million subsequent to closing.

The results of operations from the acquisition from the December 1, 2022 closing date through December 31, 2022, represented approximately $2.6 million of revenue and $1.5 million of income from operations. The Company incurred $1.3 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	164,300
Total assets acquired		164,300
Asset retirement obligations		(278)
Net assets acquired	$	164,023
Fair value of consideration paid for net assets:		
Cash consideration	$	153,916
Contingent consideration		10,107
Total fair value of consideration transferred	$	164,023

A contingent consideration liability arising from potential additional consideration in connection with the Alpha Acquisition was recognized at its fair value. The seller had the potential to earn additional cash consideration dependent upon average front month NYMEX WTI oil pricing during the first six months of 2023. The amount was to be determined on a sliding scale from zero additional consideration if such pricing was below $75.00 per barrel, up to $22.5 million of additional consideration if such pricing was at least $87.85 per barrel. This contingent consideration was not earned, and there was no remaining associated liability as of June 30, 2023. The acquisition date fair value of the potential additional consideration, totaling $10.1 million, was recorded within contingent consideration liabilities on the Company's condensed balance sheets. Changes in the fair value of the liability are recorded in other income (expense) on the Company's condensed statement of operations. For the three months ended September 30, 2023, we did not record a contingent consideration gain or loss. For the nine months ended September 30, 2023 we recorded a contingent consideration gain of $10.1 million relating to the change in fair value of the liability.

Delaware Acquisition

On December 16, 2022, the Company completed the acquisition of certain non-operated oil and gas properties, interests and related assets in the Permian Delaware Basin from a private seller, effective as of November 1, 2022 (the "Delaware Acquisition").

The total consideration at closing was $131.6 million in cash. As a result of customary post-closing adjustments, the Company increased its proved oil and natural gas properties and total consideration by $0.1 million subsequent to closing.

The results of operations from the acquisition from the December 16, 2022 closing date through December 31, 2022, represented approximately $1.2 million of revenue and $0.7 million of income from operations. The Company incurred $1.3 million of transaction costs in connection with the acquisition, which are included in general and administrative expense in the Company's statement of operations. The following table reflects the fair values of the net assets and liabilities as of the closing date of the acquisition:

		(In thousands)
Fair value of net assets:		
Proved oil and natural gas properties	$	131,773
Total assets acquired		131,773
Asset retirement obligations		(155)
Net assets acquired	$	131,618
Fair value of consideration paid for net assets:		
Cash consideration	$	131,618
Total fair value of consideration transferred	$	131,618

Pro Forma Information

The following summarized unaudited pro forma condensed statement of operations information for the three and nine months ended September 30, 2023 and 2022, assumes that each of the 2023 Bolt-on Acquisitions and 2022 Bolt-on Acquisitions occurred as of January 1, 2022. The Company prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had the Company completed the acquisitions as of January 1, 2022, or that would be attained in the future.

(In thousands)	**Three Months Ended September 30, 2023**	**Nine Months Ended September 30, 2023**	**Three Months Ended September 30, 2022**	**Nine Months Ended September 30, 2022**
Total Revenues	$ 347,895	$ 1,680,604	$ 990,599	$ 1,844,217
Net Income (Loss)	78,074	826,335	752,845	1,168,817

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

The Company historically has acquired unproved properties by purchasing individual or small groups of leases directly from mineral owners, landmen, or lease brokers, which leases historically have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. The Company generally participates in drilling activities on a heads up basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Capitalized costs associated with impaired unproved properties, which includes leases that have expired or have been deemed uneconomic, and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or impaired. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the three months ended September 30, 2023 and 2022, unproved properties of $1.4 million and $3.4 million, respectively, were impaired. For the nine months ended September 30, 2023 and 2022 unproved properties of $4.1 million and $5.3 million, respectively, were impaired.

NOTE 4 LONG-TERM DEBT

The Company's long-term debt consists of the following:

	September 30, 2023			
(In thousands)	Principal Balance	Unamortized Premium	Debt Issuance Costs, Net	Long-term Debt, Net
Revolving Credit Facility [(1)]	$ 384,000	$ —	$ —	$ 384,000
Senior Notes due 2028	705,108	8,886	(9,937)	704,057
Senior Notes due 2031	500,000	(6,823)	(9,045)	484,132
Convertible Notes due 2029	500,000	—	(14,830)	485,170
Total	$ 2,089,108	$ 2,063	$ (33,812)	$ 2,057,359

	December 31, 2022			
	Principal Balance	Unamortized Net Premium	Debt Issuance Costs, Net	Long-term Debt, Net
Revolving Credit Facility [(1)]	$ 319,000	$ —	$ —	$ 319,000
Senior Notes due 2028	724,235	10,682	(11,946)	722,972
Convertible Notes due 2029	500,000	—	(16,558)	483,442
Total	$ 1,543,235	$ 10,682	$ (28,504)	$ 1,525,413

(1) Debt issuance costs related to the Company's Revolving Credit Facility of $11.3 million and $10.9 million as of September 30, 2023 and December 31, 2022, are recorded in "Other Noncurrent Assets, Net" in the balance sheets.

Revolving Credit Facility

On June 7, 2022, the Company entered into a Third Amended and Restated Credit Agreement (as amended, modified, or supplemented through the date of this filing, the "Revolving Credit Facility") with Wells Fargo Bank, National Association, as administrative agent and collateral agent ("Agent"), and the lenders from time to time party thereto, which amended and restated the Company's prior revolving credit facility that was entered into on November 22, 2019. The Revolving Credit Facility is scheduled to mature on June 7, 2027.

The Revolving Credit Facility is comprised of revolving loans and letters of credit and is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries' (if any) oil and gas properties. As of September 30, 2023, the borrowing base was $1.8 billion and the aggregate elected commitment amount was $1.25 billion. The Company's borrowing availability under the Revolving Credit Facility is set at the lesser of the borrowing base and the elected commitment amount. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim "wildcard" redetermination available to each of the Company and the Agent (acting at the direction of the lenders holding at least two-thirds of commitments and loans outstanding under the Revolving Credit Facility) between scheduled redeterminations. Upon an acquisition of oil and gas properties with an aggregate value exceeding 5% of the borrowing base, the Company may request an additional redetermination. The scheduled redeterminations are based on a

December 31st or June 30th reserve report, as applicable, prepared under the supervision of the Company's chief engineer and, in the case of the December 31st reserve report, audited by an approved petroleum engineer (reasonably acceptable to the Agent). The Company has the option to seek commitments for term loans, which such term loans (if obtained) are capped at the least of (i) the borrowing base minus the aggregate elected commitment amount minus the then-outstanding principal amount of term loans, (ii) the aggregate elected commitment amount minus the then-outstanding principal amount of term loans and (iii) $500.0 million. Such term loans are subject to certain other terms of the Revolving Credit Facility.

At the Company's option, borrowings under the Revolving Credit Facility shall bear interest at the base rate or SOFR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the Agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from125 to 225 basis points, and the applicable margin for SOFR loans ranges from225 to 325 basis points, in each case depending on the percentage of the borrowing base utilized.

The Revolving Credit Facility contains negative covenants that limit the Company's ability, among other things, to pay dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, or make certain types of investments. In addition, the Revolving Credit Facility requires that the Company comply with the following financial covenants: (i) as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the Revolving Credit Facility) shall be no more than 3.50 to 1.00, measured on a rolling four quarter basis, and (ii) the current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under FASB Accounting Standards Codification ("ASC") Topic 815, Derivatives and Hedging ("ASC 815"), divided by consolidated current liabilities excluding current non-cash obligations under ASC 815, current maturities under the Revolving Credit Facility and current maturities of any long-term debt) shall not be less than 1.00 to 1.00. The Company is in compliance with these financial covenants as of September 30, 2023.

The Company's obligations under the Revolving Credit Facility may be accelerated, subject to customary grace and cure periods, upon the occurrence of certain Events of Default (as defined in the Revolving Credit Facility). Such Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of the Company or its subsidiaries, defaults related to judgments and the occurrence of a Change in Control (as defined in the Revolving Credit Facility).

The Company's obligations under the Revolving Credit Facility are secured by mortgages on not less than90% of the value of proven reserves associated with the oil and gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company's obligations under the Revolving Credit Facility are secured by a first priority security interest in substantially all of the Company's assets.

Senior Notes due 2028

On February 18, 2021, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "2028 Notes Indenture"), pursuant to which the Company issued $550.0 million in aggregate principal amount of 8.125% senior unsecured notes due 2028 (the "Original 2028 Notes"). On November 15, 2021, the Company issued an additional $200.0 million aggregate principal amount of 8.125% senior notes due 2028 (the "Additional 2028 Notes" and, together with the Original 2028 Notes, the "Senior Notes due 2028"). The proceeds of the Senior Notes due 2028 were used primarily to refinance existing indebtedness, and for general corporate purposes.

During the nine months ended September 30, 2023, the Company repurchased and retired $19.1 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $18.4 million in cash, plus accrued interest. During 2022, the Company repurchased and retired $25.8 million in aggregate principal amount of the Senior Notes due 2028 in open market transactions for a total of $24.9 million in cash, plus accrued interest.

The Senior Notes due 2028 will mature on March 1, 2028. Interest is payable semi-annually in arrears on each March 1 and September 1 to holders of record on the February 15 and August 15 immediately preceding the related interest payment date, at a rate of 8.125% per annum. Prior to March 1, 2024, the Company may redeem all or a part of the Senior Notes due 2028 at a redemption price equal to 100% of the principal amount of the Senior Notes due 2028 redeemed, plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On or after March 1, 2024, the Company may redeem all or a part of the Senior Notes due 2028 at redemption prices (expressed as percentages of principal amount) equal to 104.063% for the twelve-month period beginning on March 1, 2024,102.031% for the twelve-month period beginning on March 1, 2025, and 100% beginning on March 1, 2026, plus accrued and unpaid interest to the redemption date.

If a Change of Control Triggering Event (as defined in the 2028 Notes Indenture) occurs, each holder of Senior Notes due 2028 may require the Company to repurchase all or any part of that holder's the Senior Notes due 2028 for cash at a price equal to 101% of the aggregate principal amount of the the Senior Notes due 2028 repurchased, plus any accrued and unpaid interest on the the Senior Notes due 2028 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2028 Notes Indenture contains covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries, if any, to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends or distributions in respect of equity interests or redeem, repurchase or retire equity securities or subordinated indebtedness; (iii) transfer or sell certain assets; (iv) make investments; (v) create liens to secure indebtedness; (vi) enter into agreements that restrict dividends or other payments from any non-guarantor subsidiary to the Company; (vii) consolidate with or merge with or into, or sell substantially all of the Company's assets to, another person; (viii) enter into transactions with affiliates; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications, and many of these covenants will be terminated if the Senior Notes due 2028 achieve an investment grade rating from either Moody's Investors Services, Inc. or S&P Global Ratings.

The 2028 Notes Indenture contains customary events of default, including, but not limited to: (i) default for 30 days in the payment when due of interest on the Senior Notes due 2028; (ii) default in payment when due of the principal of, or premium, if any, on the Senior Notes due 2028; (iii) failure by the Company or certain of its subsidiaries, if any, to comply with certain of their respective obligations, covenants or agreements contained in the Senior Notes due 2028 or the 2028 Notes Indenture, subject to certain notice and grace periods; (iv) failure by the Company or any of its restricted subsidiaries to pay indebtedness within any applicable grace period or the acceleration of any such indebtedness if the total amount of such indebtedness exceeds $35.0 million; (v) failure by the Company or any of its restricted subsidiaries that is a Significant Subsidiary (as defined in the 2028 Notes Indenture) to pay final non-appealable judgments aggregating in excess of $35.0 million, which judgments are not paid, discharged or stayed for a period of 60 days; (vi) except as permitted by the 2028 Notes Indenture, any guarantee of the Senior Notes due 2028 is held in any judicial proceeding to be unenforceable or invalid, or ceases for any reason to be in full force and effect, or is denied or disaffirmed by a Guarantor (as defined in the 2028 Notes Indenture); and (vii) certain events of bankruptcy or insolvency described in the 2028 Notes Indenture with respect to the Company and its restricted subsidiaries that are Significant Subsidiaries.

Convertible Notes due 2029

On October 14, 2022, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the "Convertible Notes Indenture"), pursuant to which the Company issued $500.0 million in aggregate principal amount of 3.625% convertible senior notes due 2029 (the "Convertible Notes"). The proceeds of the Convertible Notes were used to refinance existing indebtedness and for other general corporate purposes. The Convertible Notes mature on April 15, 2029, unless earlier repurchased, redeemed or converted. The Convertible Notes accrue interest at a rate of 3.625% per annum, payable semi-annually in arrears on April 15 and October 15 of each year.

Before October 16, 2028, noteholders have the right to convert their Convertible Notes only upon the occurrence of certain events. From and after October 16, 2028, noteholders may convert their Convertible Notes at any time at their election until the close of business on the second scheduled trading day immediately before the maturity date. The Company will have the right to elect to settle conversions either entirely in cash or in a combination of cash and shares of its common stock. However, upon conversion of any Convertible Notes, the conversion value, which will be determined over a period of 40 trading days, will be paid in cash up to at least the principal amount of the Convertible Notes being converted. The initial conversion rate was 26.3104 shares of common stock per $1,000 principal amount of Convertible Notes, which represented an initial conversion price of approximately $38.01 per share of common stock. The conversion rate and conversion price are subject to customary anti-dilution and other adjustments upon the occurrence of certain events. As of September 30, 2023, the conversion rate was 26.4564 shares of common stock per $1,000 principal amount of Convertible Notes, which represented a conversion price of approximately $37.80 per share of common stock. In addition, if certain corporate events that constitute a "Make-Whole Fundamental Change" (as defined in the Convertible Notes Indenture) occur, then the conversion rate will, in certain circumstances, be increased for a specified period of time.

The Convertible Notes are redeemable, in whole or in part (subject to certain limitations), at the Company's option at any time, and from time to time, on or after April 15, 2026 and on or before the 40th scheduled trading day immediately before the maturity date, at a cash redemption price equal to the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date, but only if the last reported sale price per share of the Company's common stock exceeds 130% of the conversion price on (i) each of at least 20 trading days, whether or not consecutive, during the 30 consecutive trading days ending on, and including, the trading day immediately before the date the

Company sends the related redemption notice; and (ii) the trading day immediately before the date the Company sends such notice. In addition, calling any Convertible Note for redemption will constitute a Make-Whole Fundamental Change with respect to that Convertible Note, in which case the conversion rate applicable to the conversion of that Convertible Note will be increased in certain circumstances if it is converted after it is called for redemption.

If certain corporate events that constitute a “Fundamental Change” (as defined in the Convertible Notes Indenture) occur, then, subject to a limited exception for certain cash mergers, noteholders may require the Company to repurchase their Convertible Notes at a cash repurchase price equal to the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, to, but excluding, the fundamental change repurchase date. The definition of Fundamental Change includes certain business combination transactions involving the Company and certain de-listing events with respect to the Company’s common stock.

The Convertible Notes have customary provisions relating to the occurrence of “Events of Default” (as defined in the Convertible Notes Indenture), which include the following: (i) certain payment defaults on the Convertible Notes (which, in the case of a default in the payment of interest on the Convertible Notes, will be subject to a 30-day cure period); (ii) the Company’s failure to send certain notices under the Convertible Notes Indenture within specified periods of time; (iii) the Company’s failure to comply with certain covenants in the Convertible Notes Indenture relating to the Company’s ability to consolidate with or merge with or into, or sell, lease or otherwise transfer, in one transaction or a series of transactions, all or substantially all of the assets of the Company and any subsidiaries that the Company may form or acquire in the future, taken as a whole, to another person; (iv) a default by the Company in certain of its other obligations or agreements under the Convertible Notes Indenture or the Convertible Notes if such default is not cured or waived within 60 days after notice is given in accordance with the Convertible Notes Indenture; (v) certain defaults by the Company or any subsidiaries that the Company may form or acquire in the future with respect to indebtedness for borrowed money of at least $50.0 million; (vi) the rendering of certain judgments against the Company or any of its subsidiaries for the payment of at least $50.0 million, where such judgments are not paid, discharged or stayed within 60 days after the date on which the right to appeal has expired or on which all rights to appeal have been extinguished; and (vii) certain events of bankruptcy, insolvency and reorganization involving the Company or any of the Company’s significant subsidiaries that the Company may form or acquire in the future.

If an Event of Default involving bankruptcy, insolvency or reorganization events with respect to the Company (and not solely with respect to any significant subsidiary that the Company may form or acquire in the future) occurs, then the principal amount of, and all accrued and unpaid interest on, all of the Convertible Notes then outstanding will immediately become due and payable without any further action or notice by any person. If any other Event of Default occurs and is continuing, then, the Trustee, by notice to the Company, or noteholders of at least 25% of the aggregate principal amount of Convertible Notes then outstanding, by notice to the Company and the Trustee, may declare the principal amount of, and all accrued and unpaid interest on, all of the Convertible Notes then outstanding to become due and payable immediately. However, notwithstanding the foregoing, the Company may elect, at its option, that the sole remedy for an Event of Default relating to certain failures by the Company to comply with certain reporting covenants in the Convertible Notes Indenture consists exclusively of the right of the noteholders to receive special interest on the Convertible Notes for up to 365 days at a specified rate per annum not exceeding 0.25% on the principal amount of the Convertible Notes for the first 180 days and, thereafter, at a specified rate per annum not exceeding 0.50% on the principal amount of the Convertible Notes.

Capped Call Transactions

In October 2022, in connection with the Convertible Notes offering described above, the Company entered into privately negotiated capped call transactions (the “Capped Call Transactions”) with certain of the initial purchasers of the Convertible Notes and/or their respective affiliates and/or other financial institutions. The Company paid $36.1 million in total consideration to enter into the Capped Call Transactions. The Capped Call Transactions cover, subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the Convertible Notes, the number of shares of common stock initially underlying the Convertible Notes. The Capped Call Transactions are expected generally to reduce potential dilution to the common stock upon any conversion of Convertible Notes and/or offset any potential cash payments the Company is required to make in excess of the principal amount of such converted Convertible Notes, as the case may be, with such reduction and/or offset subject to a cap. The cap price of the Capped Call Transactions was initially approximately $52.17 per share of common stock, which represents a premium of 75% over the last reported sale price of the common stock of $29.81 per share on October 11, 2022, and is subject to certain customary adjustments under the terms of the Capped Call Transactions. As of September 30, 2023, the cap price of the Capped Call Transactions was approximately $51.88 per share of common stock.

Senior Notes due 2031

On May 15, 2023, the Company and Wilmington Trust, National Association, as trustee, entered into an indenture (the “2031 Notes Indenture”), pursuant to which the Company issued $500.0 million in aggregate principal amount of the Company’s 8.750% senior notes due 2031 (the “Senior Notes due 2031”). The proceeds of the Senior Notes due 2031 were used primarily to refinance existing indebtedness, and for general corporate purposes.

The Senior Notes due 2031 will mature on June 15, 2031. Interest is payable semi-annually in arrears on each June 15 and December 15, commencing December 15, 2023, to holders of record on the June 1 and December 1 immediately preceding the related interest payment date, at a rate of 8.750% per annum. Prior to June 15, 2026, the Company may redeem up to 35% of the aggregate principal amount of Senior Notes due 2031, upon not less than10 or more than 60 days’ notice, at a redemption price of 108.750% of the principal amount of the Senior Notes due 2031 redeemed, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date), in an amount not greater than the net cash proceeds of one or more equity offerings by the Company, provided that (i) at least 65% of the aggregate principal amount of Senior Notes due 2031 issued under the 2031 Notes Indenture (including any Additional Notes (as defined in the 2031 Notes Indenture) but excluding the Senior Notes due 2031 held by the Company and its Subsidiaries (as defined in the 2031 Notes Indenture)) remains outstanding immediately after the occurrence of such redemption (unless all Senior Notes due 2031 are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days of the date of the closing of each such equity offering. In addition, prior to June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031, on any one or more occasions, upon not less than 10 or more than 60 days’ notice, at a redemption price equal to 100% of the principal amount of the Senior Notes due 2031 redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date).

On or after June 15, 2026, the Company may redeem all or a part of the Senior Notes due 2031, at redemption prices (expressed as percentages of principal amount) equal to 104.375% for the twelve-month period beginning on June 15, 2026,102.188% for the twelve-month period beginning on June 15, 2027, and100% beginning on June 15, 2028, plus accrued and unpaid interest to the redemption date.

If a Change of Control Triggering Event (as defined in the 2031 Notes Indenture) occurs, each holder of Senior Notes due 2031 may require the Company to repurchase all or any part of that holder’s Senior Notes due 2031 for cash at a price equal to 101% of the aggregate principal amount of the Senior Notes due 2031 repurchased, plus any accrued and unpaid interest on the Senior Notes due 2031 repurchased to, but excluding, the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date on or prior to the date of purchase).

The 2031 Notes Indenture contains covenants that, among other things, limit the Company’s ability and the ability of its restricted subsidiaries, if any, to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends or distributions in respect of equity interests or redeem, repurchase or retire equity securities or subordinated indebtedness; (iii) transfer or sell certain assets; (iv) make investments; (v) create liens to secure indebtedness; (vi) enter into agreements that restrict dividends or other payments from any non-guarantor subsidiary to the Company; (vii) consolidate with or merge with or into, or sell substantially all of the Company’s assets to, another person; (viii) enter into transactions with affiliates; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications, and many of these covenants will be terminated if the Senior Notes due 2031 achieve an investment grade rating from either Moody’s Investors Service, Inc. or S&P Global Ratings.

The 2031 Notes Indenture contains customary events of default, including, but not limited to: (i) default for30 days in the payment when due of interest on the Senior Notes due 2031; (ii) default in payment when due of the principal of, or premium, if any, on the Senior Notes due 2031; (iii) failure by the Company or certain of its subsidiaries, if any, to comply with certain of their respective obligations, covenants or agreements contained in the Senior Notes due 2031 or the 2031 Notes Indenture, subject to certain notice and grace periods; (iv) failure by the Company or any of its restricted subsidiaries to pay indebtedness within any applicable grace period or the acceleration of any such indebtedness if the total amount of such indebtedness exceeds $35.0 million; (v) failure by the Company or any of its restricted subsidiaries that is a Significant Subsidiary (as defined in the 2031 Notes Indenture) to pay final non-appealable judgments aggregating in excess of $35.0 million, which judgments are not paid, discharged or stayed for a period of60 days; (vi) except as permitted by the 2031 Notes Indenture, any guarantee of the Senior Notes due 2031 is held in any judicial proceeding to be unenforceable or invalid, or ceases for any reason to be in full force and effect, or is denied or disaffirmed by a Guarantor (as defined in the 2031 Notes Indenture); and (vii) certain events of bankruptcy or insolvency described in the 2031 Notes Indenture with respect to the Company and its restricted subsidiaries that are Significant Subsidiaries.

NOTE 5 COMMON AND PREFERRED STOCK

Common Stock

The Company is authorized to issue up to 135,000,000 shares of common stock, par value $0.001 per share. As of September 30, 2023, the Company had 93,032,638 shares of common stock issued and outstanding.

Preferred Stock

The Company is authorized to issue up to 5,000,000 shares of preferred stock, par value $0.001 per share, with such designations, voting and other rights and preferences as may be determined from time to time by the Company's Board of Directors. As of September 30, 2023, the Company had zero shares of preferred stock issued and outstanding.

2023 Activity

Common Stock

On May 18, 2023, the Company closed an underwritten public offering of 7,647,500 shares of its common stock at a price of $29.40 per share, after deducting underwriting discounts, resulting in net proceeds of approximately $224.7 million.

During the nine months ended September 30, 2023, 98,052 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $2.6 million, which is based on the market prices on the dates the shares were surrendered.

During the nine months ended September 30, 2023, the Company issued 403,780 shares of common stock in exchange for the surrender and cancellation of a portion of the warrants originally issued by the Company at closing of the Veritas Acquisition, which immediately prior to their cancellation were exercisable for an aggregate of approximately 824,602 shares of common stock at an exercise price of $27.4946 per share.

See Note 12 for a discussion regarding issuances of shares of common stock after September 30, 2023.

Dividends

In February 2023, the Company's Board of Directors declared a cash dividend on the Company's common stock in the amount of $0.34 per share. The dividend was paid on April 28, 2023 to stockholders of record as of the close of business on March 30, 2023.

In May 2023, the Company's Board of Directors declared a cash dividend on the Company's common stock in the amount of $0.37 per share. The dividend was paid on July 31, 2023 to stockholders of record as of the close of business on June 29, 2023.

In August 2023, the Company's Board of Directors declared a cash dividend on the Company's common stock in the amount of $0.38 per share. The dividend was paid on October 31, 2023 to stockholders of record as of the close of business on September 28, 2023.

In October 2023, the Company's Board of Directors declared a cash dividend on the Company's common stock in the amount of $0.40 per share. The dividend will be paid on January 31, 2024 to stockholders of record as of the close of business on December 28, 2023.

Stock Repurchase Program

In May 2022, the Company's Board of Directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

During the nine months ended September 30, 2023, the Company repurchased 287,751 shares of its common stock under the stock repurchase program at a total cost of $8.0 million. During the nine months ended September 30, 2022, the Company repurchased 805,919 shares of its common stock under the stock repurchase program at a total cost of $21.5 million.

The Company's accounting policy upon the repurchase of shares is to deduct its par value from common stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital. All repurchased shares are included in the Company's pool of authorized but unissued shares.

NOTE 6 STOCK-BASED COMPENSATION AND WARRANTS

Stock-Based Compensation

The Company maintains the Amended and Restated 2018 Equity Incentive Plan (the "2018 Plan"), for the purpose of making equity-based awards to employees, directors and other eligible persons. As of September 30, 2023, there were 3,258,226 shares available for future awards under the 2018 Plan.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative expenses" line item in the unaudited statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Oil and natural gas properties" line item in the unaudited balance sheet.

Issuances made pursuant to the 2018 Plan are summarized as follows:

Restricted Stock Awards

The Company issues restricted stock awards ("RSAs") subject to various vesting conditions as compensation to executive officers, employees and directors of the Company. RSAs issued to employees and executive officers generally vest over three years, subject to continued employment and provided that any performance and/or market conditions are also met. RSAs issued to directors generally vest over one year, subject to continued service and provided that any performance and/or market conditions are also met. For RSAs subject to service and/or performance vesting conditions, the grant-date fair value is established based on the closing price of the Company's common stock on such date. Stock-based compensation expense for awards subject to only service conditions is recognized on a straight-line basis over the service period. Stock-based compensation expense for awards subject to both service and performance conditions is recognized on a graded basis if it is probable that the performance condition will be achieved. The Company accounts for forfeitures of awards granted under these plans as they occur in determining stock-based compensation expense.

For awards subject to a market condition, the grant-date fair value is estimated using a Monte Carlo valuation model. The Company recognizes stock-based compensation expense for awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and stock-based compensation expense for any such awards is not reversed if vesting does not actually occur. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period.

The following table reflects the outstanding RSAs and activity related thereto for the nine months ended September 30, 2023:

	Service-based Awards	
	Number of Shares	Weighted-average Grant Date Fair Value
Outstanding at December 31, 2022	316,333	$ 16.39
Shares granted	214,758	33.47
Shares forfeited	(13,404)	19.06
Shares vested	(312,226)	16.78
Outstanding at September 30, 2023	205,461	$ 25.57

At September 30, 2023, there was $3.1 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 0.88 years. For the nine months ended September 30, 2023 and 2022, the total fair value of the Company's restricted stock awards vested was $6.2 million and $4.6 million, respectively.

Performance Equity Awards

In April 2022, the Company granted performance equity awards under its 2022 executive compensation program to certain executive officers. The awards were subject to a market condition, which was based on a comparison of the Company versus a defined peer group with respect to total shareholder return ("TSR") based on the last 20 trading days of 2022 compared to the same period of 2021. Depending on the Company's TSR relative to the defined peer group, the award recipients in the aggregate could earn between zero and $2.4 million in the form of awards expected to be settled in restricted shares. In January 2023, the Company issued 74,220 restricted shares of common stock in settlement of these awards, with service-based vesting over three years. For the three months ended September 30, 2023, the Company recorded $0.1 million of compensation expense in connection with the performance equity awards.

Warrants

In January 2022, the Company issued common stock warrants as a part of the Veritas Acquisition as purchase consideration. These warrants (i) gave holders the right to purchase 1,939,998 shares of the Company's common stock at an exercise price equal to $28.30 per share (subject to certain anti-dilution adjustments), (ii) had a total fair value of $17.9 million at issuance, and (iii) are generally exercisable from April 27, 2022 until January 27, 2029. The fair value of the warrants at issuance was determined by utilizing an Option Pricing Model, which used the market value of the Company's common stock on the issue date, an exercise price of $28.30, an implied volatility of 60%, a risk-free rate of 2.14% and an implied dividend yield of 3.00%.

In March 2023, the Company issued 403,780 shares of common stock in exchange for the surrender and cancellation of a portion of the warrants originally issued by the Company at closing of the Veritas Acquisition, which immediately prior to their cancellation were exercisable for an aggregate of approximately 824,602 shares of common stock at an exercise price of $27.4946 per share. Neither the Company nor the holders paid any cash consideration in the transaction.

The following table reflects the outstanding warrants and activity related thereto for the nine months ended September 30, 2023:

	Warrants	
	Number of Warrants	Weighted-average Exercise Price
Outstanding at December 31, 2022	1,996,829	$ 27.49
Issued	—	—
Anti-Dilution Adjustments for Common Stock Dividends	38,499	27.20
Exercised	—	—
Cancelled	(824,602)	27.49
Expired	—	—
Outstanding at September 30, 2023	1,210,726	$ 26.62

NOTE 7 RELATED PARTY TRANSACTIONS

Preferred Stock Repurchase

During February 2022, the Company entered into and closed three separate stock repurchase agreements pursuant to which the Company repurchased an aggregate of 71,894 shares of the Company's 6.500% Series A Perpetual Cumulative Convertible Preferred Stock, par value $0.001 per share ("Series A Preferred Stock"), on identical financial terms from each party for an aggregate purchase price of approximately $9.5 million in cash. Of the total amount, 21,894 shares were repurchased from affiliates of TRT Holdings, Inc. for $2.9 million in cash. Two of the Company's directors were employed by TRT Holdings, Inc., which together with its affiliates beneficially owned more than 10% of our outstanding common stock at the time of the transactions described in this paragraph.

The Company's Audit Committee is responsible for approving all transactions involving related parties.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the Company's financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

NOTE 9 INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and nine months ended September 30, 2023 and 2022 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income primarily due to the recognition of a full valuation allowance during the three and nine months ended September 30, 2022, and the release of our valuation allowance in the second quarter of 2023.

In assessing the realizability of deferred tax assets ("DTAs"), management considers whether it is more likely than not that some portion, or all, of the Company's DTAs will not be realized. In making such determination, the Company considers all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the projected future income and results of operations, and (iv) its ability to use tax planning strategies. If the Company concludes that it is more likely than not that some portion, or all, of its DTAs will not be realized, the tax asset is reduced by a valuation allowance. The Company assesses the appropriateness of its valuation allowance on a quarterly basis.

The Company's income tax benefit was $20.7 million for the three months ended September 30, 2023 and current income tax expense was $19.0 million for the nine months ended September 30, 2023. The Company's current income tax expense was $1.3 million and $3.1 million for the three and nine months ended September 30, 2022. The effective tax rates for the three and nine months ended September 30, 2023 were (381.8)% and 3.4%, respectively. The effective tax rates for the three and nine months ended September 30, 2022 were 0.2% and 0.5%, respectively. The item that had the most significant impact on the difference between the statutory U.S. federal income tax rate of 21% and the effective tax rate for the three and nine months ended September 30, 2023 was the release of the valuation allowance (described below). The items that had the most significant impact on the difference between the statutory U.S. federal income tax rate of 21% and the effective tax rate for the three and nine months ended September 30, 2022, was primarily the Company's recorded valuation allowances.

As of September 30, 2023, our deferred tax assets were primarily the result of a net operating loss, interest, and tax credit carryforwards, and derivative instruments. A full valuation allowance was recorded against our net deferred tax asset balance of $156.2 million as of December 31, 2022. For the quarter ended September 30, 2023, we released a significant portion of our valuation allowance on the basis of management's reassessment of the amount of its deferred tax assets that are more likely than not to be realized. As of September 30, 2023, management determined that there is sufficient positive evidence to conclude that it is more likely than not that additional deferred taxes of $7.3 million are realizable. The Company therefore reduced the valuation allowance accordingly.

NOTE 10 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2023 and December 31, 2022:

	Fair Value Measurements at September 30, 2023 Using		
(In thousands)	**Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Commodity Derivatives – Current Assets	$ —	$ 65,160	$ —
Commodity Derivatives – Noncurrent Assets	—	29,543	—
Commodity Derivatives – Current Liabilities	—	(176,339)	—
Commodity Derivatives – Noncurrent Liabilities	—	(190,086)	—
Total	$ —	$ (271,722)	$ —

(In thousands)	Fair Value Measurements at December 31, 2022 Using Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Assets	$ —	$ 34,276	$ —
Commodity Derivatives – Noncurrent Assets	—	12,547	—
Commodity Derivatives – Current Liabilities	—	(58,418)	—
Commodity Derivatives – Noncurrent Liabilities	—	(225,905)	—
Interest Rate Derivatives – Noncurrent Assets	—	1,017	—
Contingent Consideration – Current Liabilities	—	(10,107)	—
Total	$ —	$ (246,590)	$ —

Subsequent to the issuance of the Company's financial statements as of and for the period ended December 31, 2022, the Company identified an immaterial error in the presentation of the Fair Value footnote disclosure in which the line item "Contingent Consideration – Current Liabilities" was improperly presented as a positive value as opposed to a negative value. Accordingly, within the "Contingent Consideration – Current Liabilities" line included in the table above, the Company has corrected the amount in the line item and total for the table as of December 31, 2022. Management evaluated the materiality of this error from quantitative and qualitative perspectives and concluded the error was immaterial to the prior period. The error did not impact the balance sheet, statement of operations, statement of cash flows, or statement of stockholder's equity.

Commodity Derivatives. The Level 2 instruments presented in the tables above consist of commodity derivative instruments (see Note 11). The fair value of the Company's commodity derivative instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of commodity derivative contracts is reflected in the condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Interest Rate Derivatives. The Level 2 instruments presented in the tables above consist of interest rate derivative instruments (see Note 11). The fair value of the Company's interest rate derivative instruments is determined based upon contracted notional amounts, active market-quoted interest yield curves, and time to maturity, among other things. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of interest rate derivative contracts is reflected in the condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Contingent Consideration. These Level 2 instruments presented in the tables above consist of contingent consideration liabilities that were potentially payable by the Company in connection with the Alpha Acquisition (see Note 3). The fair value of these liabilities was estimated using observable market data (NYMEX WTI forward price curve) and Monte Carlo simulation models. The acquisition date fair values were recorded within contingent consideration liabilities on the Company's balance sheets. Changes in the fair value of the liability are recorded in other income (expense) in the Company's statement of operations.

Fair Value of Other Financial Instruments

The carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Long-term debt is not presented at fair value in the balance sheets, as it is recorded at carrying value, net of unamortized debt issuance costs and unamortized premium (see Note 4). The fair value of the Company's Senior Notes due 2028, Senior Notes due 2031 and Convertible Notes was $705.1 million, $505.0 million and $615.0 million, respectively, at September 30, 2023. The fair value of the Company's Senior Notes due 2028, Senior Notes due 2031 and Convertible Notes are based on market quotes, that represent Level 2 inputs.

There is no active market for the Revolving Credit Facility. The recorded value of the Revolving Credit Facility approximates its fair value because of its floating rate structure based on the SOFR spread, secured interest, and the Company's borrowing base utilization. The fair value measurement for the Revolving Credit Facility represents Level 2 inputs.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, Asset Retirement and Environmental Obligations. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred and acquired during the nine months ended September 30, 2023 were approximately $3.6 million.

The Company accounts for acquisitions of oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy. See Note 3 for additional discussion of the Company's acquisitions of oil and natural gas properties during the nine months ended September 30, 2023 and discussion of the significant inputs to the valuations.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the nine months ended September 30, 2023.

NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes various commodity price derivative instruments to (i) reduce the effects of volatility in price changes on the crude oil and natural gas commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending. In addition, from time to time the Company utilizes interest rate swaps to mitigate exposure to changes in interest rates on the Company's variable-rate indebtedness.

All derivative instruments are recorded in the Company's balance sheet as either assets or liabilities measured at their fair value (see Note 10). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the Company's condensed statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivatives that have not been settled. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The Company has master netting agreements on individual derivative instruments with certain counterparties and therefore the current asset and liability are netted in the balance sheet and the non-current asset and liability are netted in the balance sheet for contracts with these counterparties.

Commodity Derivative Instruments

The following table presents settlements on commodity derivative instruments and unsettled gains and losses on open commodity derivative instruments for the periods presented which is recorded in the revenue section of our condensed financial statements:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	**2023**	**2022**	**2023**	**2022**
Cash Received (Paid) on Settled Derivatives	$ 5,164	$ (124,911)	$ 46,099	$ (392,385)
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	(204,712)	382,501	(34,222)	52,390
Gain (Loss) on Commodity Derivatives, Net	$ (199,548)	$ 257,590	$ 11,878	$ (339,995)

The following table summarizes open commodity derivative positions as of September 30, 2023, for commodity derivatives that were entered into through September 30, 2023, for the settlement period presented**:**

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	2023	2024	2025	2026
Oil:				
WTI NYMEX - Swaps:				
Volume (Bbl)	1,998,576	5,564,145	1,675,687	1,069,557
Weighted-Average Price ($/Bbl)	$ 76.00	$ 75.40	$ 72.11	$ 68.94
WTI NYMEX - Swaptions[(1)(2)]:				
Volume (Bbl)	—	1,800,720	776,375	2,402,795
Weighted-Average Price ($/Bbl)	$ —	$ 67.61	$ 63.41	$ 63.65
Argus American Crude WTI Midland to WTI NYMEX - Basis Swaps:				
Volume (Bbl)	1,043,534	4,350,786	1,931,776	102,291
Weighted-Average Price ($/Bbl)	$ 1.25	$ 1.20	$ 1.00	$ 1.00
WTI NYMEX - Call Options[(1)(2)]:				
Volume (Bbl)	94,300	2,594,940	4,127,565	3,102,500
Weighted-Average Price ($/Bbl)	$ 71.55	$ 68.05	$ 77.90	$ 72.59
Brent ICE - Call Options:				
Volume (Bbl)	—	—	182,500	—
Weighted-Average Price ($/Bbl)	$ —	$ —	$ 53.50	$ —
WTI NYMEX - Put Options:				
Volume (Bbl)	92,000	—	—	—
Weighted-Average Price ($/Bbl)	$ 80.00	$ —	$ —	$ —
WTI NYMEX - Collars:				
Collar Put Volume (Bbl)	1,899,676	4,693,501	811,539	159,342
Collar Call Volume (Bbl)	2,291,252	6,312,589	1,129,962	175,307
Weighted-average floor price (Bbl)	$ 72.39	$ 69.39	$ 67.76	$ 62.50
Weighted-average ceiling price (Bbl)	$ 86.02	$ 83.44	$ 77.16	$ 70.25
Natural Gas:				
Henry Hub NYMEX - Swaps:				
Volume (MMBtu)	9,716,958	36,610,787	4,085,000	1,825,000
Weighted-Average Price ($/MMBtu)	$ 3.82	$ 3.50	$ 3.59	$ 3.20
Waha Inside FERC to Henry Hub - Basis Swaps:				
Volume (MMBtu)	2,484,000	9,882,000	9,428,000	7,300,000
Weighted-Average Differential ($/MMBtu)	$ (1.00)	$ (1.00)	$ (0.98)	$ (0.81)
NE - TETCO M2 - Basis Swaps:				
Volume (MMBtu)	3,680,000	11,890,000	1,825,000	1,825,000
Weighted-Average Differential ($/MMBtu)	$ (1.12)	$ (0.73)	$ (1.14)	$ (1.14)
Henry Hub NYMEX - Call Options:				
Volume (MMBtu)	465,000	5,490,000	5,010,000	—
Weighted-Average Price ($/MMBtu)	$ 3.87	$ 3.87	$ 3.87	$ —
Henry Hub NYMEX - Collars:				
Collar Put Volume (MMBtu)	5,742,500	17,219,086	25,024,006	15,192,303
Collar Call Volume (MMBtu)	5,742,500	17,219,086	25,024,006	15,192,303
Weighted-average floor price ($/MMBtu)	$ 3.96	$ 3.16	$ 3.14	$ 3.13
Weighted-average ceiling price ($/MMBtu)	$ 6.58	$ 5.05	$ 5.40	$ 5.66

(1) Swaptions are crude oil derivative contracts that give counterparties the option to extend certain derivative contracts for additional periods. Call Options are crude oil derivative contracts sold by the Company that give counterparties the option to exercise certain derivative contracts. The volumes and prices reflected as Swaptions and Call Options in this table will only be effective if the options are exercised by the applicable counterparties.

(2) In 2027 and 2028, NOG has 2,190,000 Bbl and 366,000 Bbl open call option contracts, respectively, at a weighted average price of $80.00 per Bbl, respectively.

Interest Rate Derivative Instruments

At times, the Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of September 30, 2023, the Company had no interest rate swaps. The settlement of these derivative instruments is recognized as a component of interest expense in the condensed statements of operations. The mark-to-market component of these derivative instruments is recognized in gain (loss) on unsettled interest rate derivatives, net in the condensed statements of operations.

Other Information Regarding Derivative Instruments

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at September 30, 2023 and December 31, 2022, respectively. Certain amounts may be presented on a net basis in the condensed financial statements when such amounts are with the same counterparty and subject to a master netting arrangement.

(In thousands)

Type of Commodity	**Balance Sheet Location**	**September 30, 2023 Estimated Fair Value**	**December 31, 2022 Estimated Fair Value**
Derivative Assets:			
Commodity Price Swap Contracts	Current Assets	$ 17,669	$ 30,513
Commodity Basis Swap Contracts	Current Assets	5,420	5,620
Commodity Price Collar Contracts	Current Assets	21,943	40,652
Commodity Price Call Option Contracts	Current Assets	29,424	—
Commodity Price Put Option Contracts	Current Assets	126	—
Interest Rate Swap Contracts	Current Assets	—	1,017
Commodity Price Swap Contracts	Noncurrent Assets	2,222	11,490
Commodity Basis Swap Contracts	Noncurrent Assets	2,213	547
Commodity Price Collar Contracts	Noncurrent Assets	27,830	29,538
Commodity Price Call Option Contracts	Noncurrent Assets	5,732	—
Total Derivative Assets		$ 112,579	$ 119,377
Derivative Liabilities:			
Commodity Price Swap Contracts	Current Liabilities	$ (48,537)	$ (53,386)
Commodity Basis Swap Contracts	Current Liabilities	(6,736)	(4,407)
Commodity Price Swaptions Contracts	Current Liabilities	(23,880)	—
Commodity Price Collar Contracts	Current Liabilities	(46,120)	(29,218)
Commodity Price Call Option Contracts	Current Liabilities	(60,466)	(13,916)
Commodity Price Put Option Contracts	Current Liabilities	(24)	—
Commodity Price Swap Contracts	Noncurrent Liabilities	(19,067)	(8,343)
Commodity Basis Swap Contracts	Noncurrent Liabilities	(7,348)	(3,071)
Commodity Price Collar Contracts	Noncurrent Liabilities	(39,363)	(33,210)
Commodity Price Call Option Contracts	Noncurrent Liabilities	(94,917)	(132,794)
Commodity Price Swaptions Contracts	Noncurrent Liabilities	(37,845)	(77,515)
Total Derivative Liabilities		$ (384,301)	$ (355,860)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted in the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected in the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

(In thousands)	Estimated Fair Value at September 30, 2023 — Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 74,583	$ (9,422)	$ 65,160
Non-Current Assets	37,997	(8,453)	29,543
Total Derivative Assets	$ 112,579	$ (17,876)	$ 94,703
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (185,762)	$ 9,422	$ (176,339)
Non-Current Liabilities	(198,539)	8,453	(190,086)
Total Derivative Liabilities	$ (384,301)	$ 17,876	$ (366,425)

(In thousands)	Estimated Fair Value at December 31, 2022 — Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 77,802	$ (42,509)	$ 35,293
Non-Current Assets	41,575	$ (29,028)	12,547
Total Derivative Assets	$ 119,377	$ (71,537)	$ 47,840
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (100,927)	$ 42,509	$ (58,418)
Non-Current Liabilities	(254,933)	29,028	(225,905)
Total Derivative Liabilities	$ (355,860)	$ 71,537	$ (284,324)

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's Revolving Credit Facility. The Company's obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of September 30, 2023. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 10 for the aggregate fair value of all derivative instruments that were in a net liability position at September 30, 2023 and December 31, 2022.

NOTE 12 SUBSEQUENT EVENTS

In October 2023, the Company closed an underwritten public offering of7,475,000 shares of its common stock at a price of $38.88 per share, after deducting underwriting discounts, resulting in proceeds to the Company, before offering expenses, of approximately $290.6 million.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

Cautionary Statement Concerning Forward-Looking Statements

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our Revolving Credit Facility, our intention or ability to pay or increase dividends on our capital stock, and impairment are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production, sales, market size, collaborations, cash flows, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following:

- changes in crude oil and natural gas prices, the pace of drilling and completions activity on our current properties and properties pending acquisition;
- infrastructure constraints and related factors affecting our properties;
- cost inflation or supply chain disruptions;
- ongoing legal disputes over, and potential shutdown of, the Dakota Access Pipeline;
- our ability to acquire additional development opportunities, potential or pending acquisition transactions, the projected capital efficiency savings and other operating efficiencies and synergies resulting from our acquisition transactions, integration and benefits of property acquisitions, or the effects of such acquisitions on our company's cash position and levels of indebtedness;
- changes in our reserves estimates or the value thereof;
- disruption to our company's business due to acquisitions and other significant transactions;
- general economic or industry conditions, nationally and/or in the communities in which our company conducts business;
- changes in the interest rate environment, legislation or regulatory requirements;
- conditions of the securities markets;
- risks associated with our Convertible Notes, including the potential impact that the Convertible Notes may have on our financial position and liquidity, potential dilution, and that provisions of the Convertible Notes could delay or prevent a beneficial takeover of our company;
- the potential impact of the capped call transactions undertaken in tandem with the Convertible Notes issuance, including counterparty risk;
- increasing attention to environmental, social and governance matters;
- our ability to consummate any pending acquisition transactions;
- other risks and uncertainties related to the closing of pending acquisition transactions;
- our ability to raise or access capital;
- cyber-incidents could have a material adverse effect on our business, financial condition or results of operations;
- changes in accounting principles, policies or guidelines;
- events beyond our control, including a global or domestic health crisis, acts of terrorism, political or economic instability or armed conflict in oil and gas producing regions; and
- other economic, competitive, governmental, regulatory and technical factors affecting our operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022, as updated by subsequent reports we file with the SEC (including this report), which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Overview

Our primary strategy is to invest in non-operated minority working and mineral interests in oil and gas properties, with a core area of focus in the premier basins within the United States. Using this strategy, we had participated in 9,489 gross (923.7 net) producing wells as of September 30, 2023. As of September 30, 2023, we had leased approximately 272,397 net acres, of which approximately 89% were developed and all were located in the United States.

We have grown and diversified our business significantly over the last several years. Prior to 2020, we focused our operations exclusively on oil-weighted properties in the Williston Basin. We first expanded beyond the Williston Basin in 2020, with several small acquisitions in the Permian Basin. In 2021 and 2022, we accelerated our diversification outside the Williston Basin via larger acquisitions, including the acquisition of significant producing natural gas properties in the Appalachian Basin and several acquisitions in the Permian Basin. We have also added to our legacy position in the Williston Basin via larger acquisitions. See Note 3 to our condensed financial statements for further details regarding our recent acquisition activity.

Our average daily production in the third quarter of 2023 was approximately 102,327 Boe per day, of which approximately 62% was oil. This was a 29% increase in production compared to the third quarter of 2022, primarily due to production attributable to recent acquisitions and new wells added to production. During the three months ended September 30, 2023, we added 22.6 net wells to production (excluding wells producing at closing of the Novo Acquisition and in-quarter ground game acquisitions).

Our percentage of production volumes by basin for the three months ended September 30, 2023 and 2022 were as follows:

	Three Months Ended September 30, 2023				Three Months Ended September 30, 2022			
	Williston	Permian	Appalachian	Total	Williston	Permian	Appalachian	Total
Oil (Bbl)	55 %	45 %	— %	100 %	71 %	29 %	— %	100 %
Natural Gas and NGLs (Mcf)	37 %	36 %	27 %	100 %	40 %	21 %	39 %	100 %
Total (Boe)	48 %	42 %	10 %	100 %	57 %	26 %	17 %	100 %

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

- *Commodity price differentials*. The price differential between our well head price for oil and the NYMEX WTI benchmark price is primarily driven by the cost to transport oil via train, pipeline or truck to refineries. The price differential between our well head price for natural gas and NGLs and the NYMEX Henry Hub benchmark price is primarily driven by gathering and transportation costs.

- *Gain (loss) on commodity derivatives, net.* We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (i) cash gains and losses we recognize on settled commodity derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period end.

- *Production expenses.* Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

- *Production taxes.* Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- *Depreciation, depletion, amortization and accretion.* Depreciation, depletion, amortization and accretion includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method. Accretion expense relates to the passage of time of our asset retirement obligations.

- *General and administrative expenses.* General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

- *Interest expense.* We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our unproved cost pool. We include interest expense that is not capitalized into the full cost pool, the amortization of deferred financing costs and bond premiums (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

- *Income tax expense.* Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;
- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in commodity prices;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of substantially all of our acreage and wells in the Williston, Permian and Appalachian Basins subjects our operating results to factors specific to these regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or more of these regions.

The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the price differentials between the applicable benchmark and the sales prices we receive for our production. Our oil price differential to the NYMEX benchmark price during the third quarter of 2023 was $2.84 per barrel, as compared to $0.84 per barrel in the third quarter of 2022. Our net realized gas price in the third quarter of 2023 was $2.19 per Mcf, representing 82% realization relative to average Henry Hub pricing, compared to a net realized gas price of $8.43 per Mcf in the third quarter of 2022, which represented 106% realization relative to average Henry Hub pricing. Fluctuations in our oil and gas price realizations are due to several factors such as pricing by basin, gathering and transportation costs, transportation method, takeaway capacity relative to production levels, regional storage capacity, seasonal refinery maintenance temporarily depressing demand, and in the case of gas realizations, the price of NGLs.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the type and amount of proppant. Since 2021, we have observed inflationary pressures on drilling and other operating costs due to various factors, such as higher commodity prices, labor shortages, supply chain disruptions and other factors. During the first nine months of 2023, the weighted average gross authorization for expenditure (or AFE) cost for wells we elected to participate in was $9.4 million, compared to $8.0 million for the wells we elected to participate in during 2022.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially production from properties within the United States, the production quota set by OPEC, and the strength of the U.S. dollar can significantly impact oil prices. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the three and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30,	
	2023	2022
Average NYMEX Prices[1]		
Natural Gas (per Mcf)	$ 2.66	$ 7.95
Oil (per Bbl)	$ 82.32	$ 91.38

(1) Based on average NYMEX closing prices.

	Nine Months Ended September 30,	
	2023	2022
Average NYMEX Prices[1]		
Natural Gas (per Mcf)	$ 2.58	$ 6.71
Oil (per Bbl)	$ 77.33	$ 98.31

(1) Based on average NYMEX closing prices.

We have entered into derivatives contracts to hedge commodity price risk on a portion of our future expected oil and natural gas production. For a summary as of September 30, 2023, of our open commodity price derivative contracts for future periods, see “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” in Part I, Item 3 below. See also Note 11 to our condensed financial statements.

Results of Operations for the Three Months Ended September 30, 2023 and September 30, 2022

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Three Months Ended September 30,		
	2023	2022	% Change
Net Production:			
Oil (Bbl)	5,847,894	4,149,841	41 %
Natural Gas and NGLs (Mcf)	21,396,966	18,776,821	14 %
Total (Boe)	9,414,055	7,279,311	29 %
Net Sales (in thousands):			
Oil Sales	464,793	375,732	24 %
Natural Gas and NGL Sales	46,858	158,318	(70) %
Gain (Loss) on Settled Commodity Derivatives	5,164	(124,911)	
Gain (Loss) on Unsettled Commodity Derivatives	(204,712)	382,501	
Other Revenue	1,870	—	
Total Revenues	313,973	791,640	(60) %
Average Sales Prices:			
Oil (per Bbl)	$ 79.48	$ 90.54	(12) %
Effect of Gain (Loss) on Settled Oil Derivatives on Average Price (per Bbl)	(2.58)	(19.12)	
Oil Net of Settled Oil Derivatives (per Bbl)	76.90	71.42	8 %
Natural Gas and NGLs (per Mcf)	2.19	8.43	(74) %
Effect of Gain (Loss) on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.95	(2.43)	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	3.14	6.00	(48) %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	54.35	73.37	(26) %
Effect of Gain (Loss) on Settled Commodity Derivatives on Average Price (per Boe)	0.55	(17.16)	
Realized Price on a Boe Basis Including Settled Commodity Derivatives	54.90	56.21	(2) %
Operating Expenses (in thousands):			
Production Expenses	$ 82,506	$ 68,478	20 %
Production Taxes	42,158	42,273	— %
General and Administrative Expenses	11,846	10,278	15 %
Depletion, Depreciation, Amortization and Accretion	133,791	65,975	103 %
Other Expense	1,235	—	
Costs and Expenses (per Boe):			
Production Expenses	$ 8.76	$ 9.41	(7) %
Production Taxes	4.48	5.81	(23) %
General and Administrative Expenses	1.26	1.41	(11) %
Depletion, Depreciation, Amortization and Accretion	14.21	9.06	57 %
Net Producing Wells at Period End	923.7	761.2	21 %

Oil and Natural Gas Sales

In the third quarter of 2023, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, was $511.7 million, compared to $534.1 million in the third quarter of 2022. This 4% reduction was driven by a 26% decrease in realized prices, excluding the effect of settled commodity derivatives, partially offset by a 29% increase in production volumes. The lower average realized price in the third quarter of 2023 as compared to the same period in 2022 was driven by a $6.24 per Mcf (or 74%) decrease in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the third quarter of 2023 compared to the same period of 2022. The lower average realized price in the third quarter of 2023 compared to the same period in 2022 was also driven by 12% lower average NYMEX oil prices and a higher average oil price differential. Oil price differential during the third quarter of 2023 was $2.84 per barrel, as compared to $0.84 per barrel in the third quarter of 2022.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas production from existing wells. Acquisitions were a significant driver of our 29% increase in production levels in the third quarter of 2023 compared to the same period of 2022.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our gain (loss) on commodity derivatives, net, was a loss of $199.5 million in the third quarter of 2023, compared to a gain of $257.6 million in the third quarter of 2022. Gain (loss) on commodity derivatives, net, is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For the third quarter of 2023, we realized a gain on settled commodity derivatives of $5.2 million, compared to a $124.9 million loss in the third quarter of 2022. The increased gain on settled derivatives was primarily due to a significant decrease in the average NYMEX oil price in the third quarter of 2023 compared to the same period of 2022. The average NYMEX oil price for the third quarter of 2023 was $82.32 per barrel, compared to $91.38 per barrel for the third quarter of 2022. During the third quarter of 2023, our derivative settlements included 1.9 million barrels of oil at an average settlement price of $76.73 per barrel. During the third quarter of 2022, our settled commodity derivatives included 2.8 million barrels of oil at an average settlement price of $63.88 per barrel. Our average realized price (including all commodity derivative cash settlements) in the third quarter of 2023 was $54.90 per Boe compared to $56.21 per Boe in the third quarter of 2022. The gain (loss) on settled commodity derivatives increased our average realized price per Boe by $0.55 in the third quarter of 2023 and decreased our average realized price per Boe by $17.16 in the third quarter of 2022.

Unsettled commodity derivative gains and losses was a loss of $204.7 million in the third quarter of 2023, compared to a gain of $382.5 million in the third quarter of 2022. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2023, all of our derivative contracts are recorded at their fair value, which was a net liability of $271.7 million, a change of $35.2 million from the $236.5 million net liability recorded as of December 31, 2022. The increase in liability at September 30, 2023 as compared to December 31, 2022 was primarily due to changes in forward commodity prices relative to prices on our open commodity derivative contracts since December 31, 2022. Our open commodity derivative contracts are summarized in “Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Production Expenses

Production expenses were $82.5 million in the third quarter of 2023, compared to $68.5 million in the third quarter of 2022. On a per unit basis, production expenses were $8.76 per Boe in the third quarter of 2023 compared to $9.41 per Boe in the third quarter of 2022. The lower production expenses per Boe was driven by decreased salt water disposal costs and workover expenses in the third quarter of 2023 compared to the third quarter of 2022. On an absolute dollar basis, the increase in our production expenses in the third quarter of 2023 compared to the third quarter of 2022 was primarily due to a 29% increase in production volumes and a 21% increase in the total number of net producing wells .

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $42.2 million in the third quarter of 2023, compared to $42.3 million in the third quarter of 2022. As a percentage of oil and natural gas sales, our production taxes were 8.2% and 7.9% in the third quarter of 2023 and 2022, respectively. The fluctuation in our average production tax rate from year to year is primarily due to changes in our oil sales as a percentage of our total oil and gas sales as well as the mix of our production by basin. Oil sales are taxed at a higher rate than natural gas sales.

General and Administrative Expenses

General and administrative expenses were $11.8 million in the third quarter of 2023 compared to $10.3 million in the third quarter of 2022. The increase was primarily due to a $0.5 million increase in acquisition-related costs in the third quarter of 2023 as compared to the third quarter of 2022, coupled with an increase of $1.0 million in professional fees and other.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $133.8 million in the third quarter of 2023, compared to $66.0 million in the third quarter of 2022. Depletion expense, the largest component of DD&A, increased by $67.7 million in the third quarter of 2023 compared to the third quarter of 2022. The aggregate increase in depletion expense was driven by a 29% increase in production levels and a 58% increase in the depletion rate per Boe. On a per unit basis, depletion expense was $14.11 per Boe in the third quarter of 2023 compared to $8.95 per Boe in the third quarter of 2022. The higher depletion rate per Boe was primarily driven by a significant increase to our depletable base, due to the closing of several larger acquisitions in 2022 and 2023 (see Note 3 to our condensed financial statements). Depreciation, amortization and accretion was $1.0 million and $0.8 million in the third quarter of 2023 and 2022, respectively. The following table summarizes DD&A expense per Boe for the third quarter of 2023 and 2022:

	Three Months Ended September 30,			
	2023	2022	$ Change	% Change
Depletion	$ 14.11	$ 8.95	$ 5.16	58 %
Depreciation, Amortization and Accretion	0.10	0.11	(0.01)	(9) %
Total DD&A Expense	$ 14.21	$ 9.06	$ 5.15	57 %

Interest Expense

Interest expense, net of capitalized interest, was $37.0 million in the third quarter of 2023 compared to $20.1 million in the third quarter of 2022. The increase was primarily due to higher levels of debt outstanding during the third quarter of 2023 compared to the third quarter of 2022. Additionally, higher interest rates on our floating rate debt contributed to higher interest expense in the third quarter of 2023 compared to the third quarter of 2022.

Income Taxes

During the third quarter of 2023, we recorded income tax benefit of $20.7 million related to federal and state income taxes as a result of the release of our valuation allowance in the second quarter of 2023. During the third quarter of 2022, we recorded income tax expense of $1.3 million related to state income taxes as the Company maintained a full valuation allowance for its deferred tax assets.

Results of Operations for the Nine Months Ended September 30, 2023and September 30, 2022

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Nine Months Ended September 30,		
	2023	2022	% Change
Net Production:			
Oil (Bbl)	15,676,829	11,775,526	33 %
Natural Gas and NGLs (Mcf)	59,230,464	51,188,941	16 %
Total (Boe)	25,548,573	20,307,016	26 %
Net Sales (in thousands):			
Oil Sales	$ 1,174,006	$ 1,128,439	4 %
Natural Gas and NGL Sales	180,370	411,712	(56) %
Gain (Loss) on Settled Commodity Derivatives	46,099	(392,385)	
Gain (Loss) on Unsettled Commodity Derivatives	(34,222)	52,390	
Other Revenue	6,488	—	
Total Revenues	1,372,742	1,200,156	14 %
Average Sales Prices:			
Oil (per Bbl)	$ 74.89	$ 95.83	(22) %
Effect of Gain (Loss) on Settled Oil Derivatives on Average Price (per Bbl)	(0.92)	(25.72)	
Oil Net of Settled Oil Derivatives (per Bbl)	73.97	70.11	6 %
Natural Gas and NGLs (per Mcf)	3.05	8.04	(62) %
Effect of Gain (Loss) on Settled Natural Gas Derivatives on Average Price (per Mcf)	1.02	(1.93)	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	4.07	6.11	(33) %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	53.01	75.84	(30) %
Effect of Gain (Loss) on Settled Commodity Derivatives on Average Price (per Boe)	1.80	(19.32)	
Realized Price on a Boe Basis Including Settled Commodity Derivatives	54.81	56.52	(3) %
Operating Expenses (in thousands):			
Production Expenses	$ 244,944	$ 187,659	31 %
Production Taxes	114,215	120,729	(5) %
General and Administrative Expenses	37,248	32,155	16 %
Depletion, Depreciation, Amortization and Accretion	334,836	173,956	92 %
Other Expense	3,681	—	
Costs and Expenses (per Boe):			
Production Expenses	$ 9.59	$ 9.24	4 %
Production Taxes	4.47	5.95	(25) %
General and Administrative Expenses	1.46	1.58	(8) %
Depletion, Depreciation, Amortization and Accretion	13.11	8.57	53 %
Net Producing Wells at Period End	923.7	761.2	21 %

Oil and Natural Gas Sales

In the first nine months of 2023, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, was $1,354.4 million, compared to $1,540.2 million in the first nine months of 2022. This 12.0% reduction was driven by a 30% decrease in realized prices, excluding the effect of settled commodity derivatives, partially offset by a 26% increase in production volumes. The lower average realized price in the first nine months of 2023 as compared to the same period in 2022 was driven by a $4.99 per Mcf (or 62%) decrease in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the first nine months of 2023 compared to the same period of 2022. The lower average realized price in the first nine months of 2023 compared to the same period in 2022 was also driven by 22% lower average NYMEX oil and natural gas prices, partially offset by a lower average oil price differential. Oil price differential during the first nine months of 2023 was $2.44 per barrel, as compared to $2.48 per barrel in the first nine months of 2022.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas production from existing wells. Acquisitions were a significant driver of our 26% increase in production levels in the first nine months of 2023 compared to the same period of 2022.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil and natural gas production. Our gain (loss) on commodity derivatives, net, was a gain of $11.9 million in the first nine months of 2023, compared to a loss of $340.0 million in the first nine months of 2022. Gain (loss) on commodity derivatives, net, is comprised of (i) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (ii) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

For the first nine months of 2023, we realized a gain on settled commodity derivatives of $46.1 million, compared to a $392.4 million loss in the first nine months of 2022. The increased gain on settled derivatives was primarily due to a significant decrease in the average NYMEX oil price in the first nine months of 2023 compared to the same period of 2022. The average NYMEX oil price for the first nine months of 2023 was $77.33 per barrel, compared to $98.31 per barrel for the first nine months of 2022. During the first nine months of 2023, our derivative settlements included 6.1 million barrels of oil at an average settlement price of $74.92 per barrel. During the first nine months of 2022, our settled commodity derivatives included 8.1 million barrels of oil at an average settlement price of $61.91 per barrel. Our average realized price (including all commodity derivative cash settlements) in the first nine months of 2023 was $54.81 per Boe compared to $56.52 per Boe in the first nine months of 2022. The gain (loss) on settled commodity derivatives increased our average realized price per Boe by $1.80 in the first nine months of 2023 and decreased our average realized price per Boe by $19.32 in the first nine months of 2022.

Unsettled commodity derivative gains and losses was a loss of $34.2 million in the first nine months of 2023, compared to a gain of $52.4 million in the first nine months of 2022. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our commodity derivatives. Any gains on our unsettled commodity derivatives are expected to be offset by lower wellhead revenues in the future, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2023, all of our derivative contracts are recorded at their fair value, which was a net liability of $271.7 million, a change of $35.2 million from the $236.5 million net liability recorded as of December 31, 2022. The increase in liability at September 30, 2023 as compared to December 31, 2022 was primarily due to changes in forward commodity prices relative to prices on our open commodity derivative contracts since December 31, 2022. Our open commodity derivative contracts are summarized in "Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Production Expenses

Production expenses were $244.9 million in the first nine months of 2023, compared to $187.7 million in the first nine months of 2022. On a per unit basis, production expenses were $9.59 per Boe in the first nine months of 2023 compared to $9.24 per Boe in the first nine months of 2022. The higher production expense was driven by increased service and maintenance costs and higher workover expenses per Boe in the first nine months of 2023. On an absolute dollar basis, the increase in our production expenses in the first nine months of 2023 compared to the first nine months of 2022 was primarily due to a 26% increase in production volumes, a 21% increase in the total number of net producing wells and the aforementioned higher per unit costs.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $114.2 million in the first nine months of 2023, compared to $120.7 million in the first nine months of 2022. As a percentage of oil and natural gas sales, our production taxes were 8.4% and 7.8% in the first nine months of 2023 and 2022, respectively. The fluctuation in our average production tax rate from year to year is primarily due to changes in our oil sales as a percentage of our total oil and gas sales as well as the mix of our production by basin. Oil sales are taxed at a higher rate than natural gas sales.

General and Administrative Expenses

General and administrative expenses were $37.2 million in the first nine months of 2023 compared to $32.2 million in the first nine months of 2022. The increase was primarily due to increases of $2.0 million in compensation expense and $1.9 million in professional fees in the first nine months of 2023 as compared to the first nine months of 2022.

Depletion, Depreciation, Amortization and Accretion

DD&A was $334.8 million in the first nine months of 2023, compared to $174.0 million in the first nine months of 2022. Depletion expense, the largest component of DD&A, increased by $160.3 million in the first nine months of 2023 compared to the first nine months of 2022. The aggregate increase in depletion expense was driven by a 26% increase in production levels and a 54% increase in the depletion rate per Boe. On a per unit basis, depletion expense was $13.00 per Boe in the first nine months of 2023 compared to $8.46 per Boe in the first nine months of 2022. The higher depletion rate per Boe was primarily driven by a significant increase to our depletable base, due to the closing of several larger acquisitions in the second half of 2022 and the the first nine months of 2023 (see Note 3 to our condensed financial statements). Depreciation, amortization and accretion was $2.7 million and $2.2 million in the first nine months of 2023 and 2022, respectively. The following table summarizes DD&A expense per Boe for the first nine months of 2023 and 2022:

	Nine Months Ended September 30,			
	2023	2022	$ Change	% Change
Depletion	$ 13.00	$ 8.46	$ 4.54	54 %
Depreciation, Amortization and Accretion	0.11	0.11	—	— %
Total DD&A Expense	$ 13.11	$ 8.57	$ 4.54	53 %

Interest Expense

Interest expense, net of capitalized interest, was $99.2 million in the first nine months of 2023 compared to $56.5 million in the first nine months of 2022. The increase was primarily due to higher levels of debt outstanding during the first nine months of 2023 compared to the first nine months of 2022. Additionally, higher interest rates on our floating rate debt contributed to higher interest expense in the first nine months of 2023 compared to the first nine months of 2022.

Income Taxes

During the first nine months of 2023, we recorded income tax expense of $19.0 million related to federal and state income taxes as a result of the release of our valuation allowance during the period. During the first nine months of 2022, we recorded income tax expense of $3.1 million related to state income taxes as the Company maintained a full valuation allowance for its deferred tax assets. The effective tax rate for the first nine months of 2023 was 3.4% compared to an effective tax rate of 0.5% for the first nine months of 2022. The difference was due primarily to the release of our full valuation allowance in 2023.

Liquidity and Capital Resources

Overview

Our main sources of liquidity and capital resources as of the date of this report have been internally generated cash flow from operations, proceeds from equity and debt financings, and credit facility borrowings. Our primary uses of capital have been for the acquisition, development and operation of our oil and natural gas properties and for shareholder returns. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

In January 2023, we completed the MPDC Acquisition for total cash consideration of $319.9 million, in June 2023 we completed the Forge Acquisition for total cash consideration of $167.9 million, and in August 2023 we completed the Novo Acquisition for total cash consideration of $468.4 million (see Note 3 to our condensed financial statements).

During the first nine months of 2023, to finance the foregoing acquisitions, reduce borrowings under our Revolving Credit Facility, and maintain a strong balance sheet, we completed a $224.7 million common stock offering and issued $500.0 million aggregate principal amount of Senior Notes due 2031. In addition, subsequent to September 30, 2023, we completed an offering of common stock resulting in proceeds of $290.6 million to the Company, before offering expenses, to further reduce borrowings under our Revolving Credit Facility (see Note 12 to our condensed financial statements).

During the nine months ended September 30, 2023, we repurchased and retired (i) 287,751 shares of our common stock for total consideration of $8.0 million and (ii) $19.1 million aggregate principal amount of our Senior Notes due 2028 for total consideration of $18.4 million, plus accrued interest.

As of September 30, 2023, we had outstanding total debt of $2,089.1 million consisting of $384.0 million of borrowings under our Revolving Credit Facility, $705.1 million aggregate principal amount of our Senior Notes due 2028, $500.0 million aggregate principal amount of our Senior Notes due 2031, and $500.0 million aggregate principal amount of our Convertible Notes.

As of September 30, 2023, we had total liquidity of $879.0 million, consisting of $866.0 million of committed borrowing availability under the Revolving Credit Facility and $13.0 million of cash on hand.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 91% and 70% of our total oil and gas sales in the third quarter of 2023 and 2022, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas and NGL prices. We seek to maintain a robust hedging program to mitigate volatility in commodity prices with respect to a portion of our expected production. For the nine months ended September 30, 2023, we hedged approximately 65% of our crude oil production and approximately 64% of our natural gas and NGL production. For a summary as of September 30, 2023, of our open commodity price derivative contracts for future periods, see "Quantitative and Qualitative Disclosures about Market Risk" in Part I, Item 3 below.

With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months and, based on current expectations, for the long term. However, we may seek additional access to capital and liquidity. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

Our recent capital commitments have been to fund acquisitions and development of oil and natural gas properties. We expect to fund our near-term capital requirements and working capital needs with cash flows from operations and available borrowing capacity under our Revolving Credit Facility. Our capital expenditures could be curtailed if our cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

Working Capital

Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, collection of receivables, expenditures related to our development and production operations and the impact of our outstanding derivative instruments.

At September 30, 2023, we had a working capital deficit of $132.9 million, compared to a deficit of $24.5 million at December 31, 2022. Current assets increased by $149.1 million and current liabilities increased by $257.5 million at September 30, 2023, compared to December 31, 2022. The increase in current assets is due to a $29.9 million increase in fair value of our derivative instruments as a result of commodity price changes and an increase of $92.2 million in accounts receivable. The increase in current liabilities is primarily related to a $139.7 million increase in our accounts payable and accrued liabilities due in part to increased completion activity levels on our properties and a $117.9 million increase in our derivative instruments as a result of the decrease in fair value.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. We typically enter into commodity derivative transactions covering a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 36 months. Our cash flows for the nine months ended September 30, 2023 and 2022 are presented below:

	Nine Months Ended September 30,	
(In thousands, unaudited)	**2023**	**2022**
Net Cash Provided by Operating Activities	$ 840,959	$ 641,039
Net Cash Used for Investing Activities	(1,484,203)	(858,542)
Net Cash Provided by Financing Activities	653,668	217,112
Net Change in Cash	$ 10,424	$ (390)

Cash Flows from Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2023 was $841.0 million, compared to $641.0 million in the same period of the prior year. This increase was due to significantly higher production volumes and higher realized oil prices (including the effect of settled derivatives), offset by lower realized natural gas prices (including the effect of settled derivatives) and higher operating costs. Net cash provided by operating activities is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital and other items (as reflected in our statements of cash flows) in the nine months ended September 30, 2023 was a deficit of $82.6 million compared to a deficit of $115.4 million in the same period of the prior year.

Cash Flows from Investing Activities

Cash flows used in investing activities during the nine months ended September 30, 2023 and 2022 were $1,484.2 million and $858.5 million, respectively. The increase in cash used in investing activities for the first nine months of 2023 as compared to the same period of 2022 was attributable to a $658.2 million increase in our capital expenditures for oil and natural gas properties spending, which included the closing of our MPDC Acquisition, Forge Acquisition and Novo Acquisition in the first nine months of 2023. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $281.5 million and $164.2 million at September 30, 2023 and 2022, respectively.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity. For instance, during the nine months ended September 30, 2023, our capitalized costs incurred, excluding non-cash consideration, for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $1,638.2 million, while the actual cash spend in this regard amounted to $1,483.6 million.

Development and acquisition activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns. Our cash spend for development and acquisition activities for the nine months ended September 30, 2023 and 2022 are summarized in the following table:

	Nine Months Ended September 30,	
(In millions, unaudited)	**2023**	**2022**
Drilling and Development Capital Expenditures	$ 484.3	$ 270.4
Acquisition of Oil and Natural Gas Properties	996.6	551.5
Other Capital Expenditures	2.7	3.6
Total	$ 1,483.6	$ 825.5

Cash Flows from Financing Activities

Net cash provided by financing activities was $653.7 million during the nine months ended September 30, 2023, compared to net cash provided by financing activities of $217.1 million during the nine months ended September 30, 2022. For the nine months September 30, 2023, cash provided by financing activities was primarily related to the issuance of the Senior Notes due 2031 of $492.8 million, the issuance of common stock of $224.7 million, and $65.0 million of net advances under our Revolving Credit Facility partially offset by $8.0 million in repurchases of common stock, $18.4 million in repurchases of our Senior Notes due 2028, and $88.7 million of common stock dividend payments. For the nine months ended September 30, 2022, cash provided by financing activities was primarily related to $386.0 million of net advances under our Revolving Credit Facility, which was partially offset by $21.5 million in repurchases of common stock, $19.8 million in repurchases of our Senior Notes due 2028, $81.2 million in repurchases of Series A Preferred Stock, $32.0 million of common stock dividend payments and $5.9 million of preferred stock dividend payments.

Revolving Credit Facility

We have a Revolving Credit Facility with Wells Fargo Bank, as administrative agent, and the lenders from time to time party thereto. The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to our oil and gas properties. As of September 30, 2023, the Revolving Credit Facility had a borrowing base of $1.80 billion and an elected commitment amount of $1.25 billion, and we had $384.0 million in borrowings outstanding under the facility, leaving $866.0 million in available committed borrowing capacity. See Note 4 to our condensed financial statements for further details regarding the Revolving Credit Facility.

Senior Notes due 2028

As of September 30, 2023, we had outstanding $705.1 million aggregate principal amount of our Senior Notes due 2028. See Note 4 to our condensed financial statements for further details regarding the Senior Notes due 2028.

Senior Notes due 2031

As of September 30, 2023, we had outstanding $500.0 million million aggregate principal amount of our Senior Notes due 2031. See Note 4 to our condensed financial statements for further details regarding the Senior Notes due 2031.

Convertible Notes

As of September 30, 2023, we had outstanding $500.0 million aggregate principal amount of our Convertible Notes. See Note 4 to our condensed financial statements for further details regarding the Convertible Notes.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Higher prices for oil and natural gas typically result in increases in the costs of materials, services and personnel. We budgeted for a 5-10% increase in drilling and completion and other associated costs in 2023 compared to 2022.

Contractual Obligations and Commitments

Please see our disclosure of contractual obligations and commitments as of December 31, 2022, included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

Critical Accounting Estimates

Critical accounting estimates are those estimates made in accordance with GAAP that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on our financial condition or results of operations. Our critical accounting estimates include impairment testing of natural gas and crude oil production properties, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting estimates from those reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

A description of our critical accounting policies, including estimates, was provided in Note 2 to our financial statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk*

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022 and, except as set forth below, have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to commodity price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

The following table summarizes our open crude oil derivative contracts as of September 30, 2023, by fiscal quarter.

Crude Oil Contracts

	Swaps[(1)]		Collars			
Settlement Period	Volume (Bbls)	Weighted Average Price ($/Bbl)	Collar Call Volume (Bbls)	Collar Put Volume (Bbls)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Floor Price ($/Bbl)
2023:						
Q4	1,998,576	$ 76.00	2,291,252	1,899,676	$ 86.02	$ 72.39
2024:						
Q1	1,501,203	$ 77.19	2,218,397	1,565,178	$ 84.56	$ 70.00
Q2	1,418,017	76.22	2,128,387	1,488,267	84.32	69.23
Q3	1,513,456	74.71	1,012,056	860,256	80.70	68.92
Q4	1,131,469	72.94	953,749	779,800	81.75	68.99
2025:						
Q1	432,749	$ 72.20	413,286	314,849	$ 79.20	$ 67.84
Q2	417,633	72.42	273,171	199,233	75.49	67.63
Q3	414,394	71.90	234,994	161,970	75.76	67.88
Q4	410,911	71.90	208,511	135,487	76.87	67.63
2026:						
Q1	263,726	$ 69.05	43,226	39,289	$ 70.25	$ 62.50
Q2	266,657	68.98	43,707	39,727	70.25	62.50
Q3	269,587	68.91	44,187	40,163	70.25	62.50
Q4	269,587	68.83	44,187	40,163	70.25	62.50

(1) This table does not include volumes subject to swaptions and call options, which are crude oil derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. See Note 11 to our condensed financial statements for further details regarding our commodity derivatives, including the swaptions and call options that are not included in the foregoing table.

The following table summarizes our open natural gas derivative contracts as of September 30, 2023, by fiscal quarter.

Natural Gas Contracts						
	Swaps[(1)]		Collars			
Contract Period	Volume (MMBTU)	Weighted Average Price ($/MMBTU)	Collar Call Volume (MMBTU)	Collar Put Volume (MMBTU)	Weighted Average Ceiling Price ($/MMBTU)	Weighted Average Floor Price ($/MMBTU)
2023:						
Q4	9,716,958	$ 3.82	5,742,500	5,742,500	$ 6.58	$ 3.96
2024:						
Q1	9,916,616	$ 3.60	3,825,000	3,825,000	$ 5.39	$ 3.36
Q2	9,950,805	3.47	3,222,500	3,222,500	4.70	3.15
Q3	9,940,457	3.47	4,600,000	4,600,000	4.80	3.08
Q4	6,802,909	3.46	5,571,586	5,571,586	5.22	3.10
2025:						
Q1	1,485,000	$ 3.61	6,971,417	6,971,417	$ 5.58	$ 3.14
Q2	915,000	3.60	6,471,297	6,471,297	5.23	3.14
Q3	920,000	3.60	6,107,569	6,107,569	5.31	3.14
Q4	765,000	3.52	5,473,723	5,473,723	5.46	3.13
2026:						
Q1	450,000	$ 3.20	4,048,249	4,048,249	$ 5.66	$ 3.13
Q2	455,000	3.20	4,184,706	4,184,706	5.66	3.13
Q3	460,000	3.20	4,184,706	4,184,706	5.66	3.13
Q4	460,000	3.20	2,774,642	2,774,642	5.66	3.13

(1) This table does not include volumes subject to call options, which are natural gas derivative contracts we have entered into which may increase our swapped volumes at the option of our counterparties. This table also does not include basis swaps. See Note 11 to our condensed financial statements for further details regarding our commodity derivatives, including the call options and basis swaps that are not included in the foregoing table.

Interest Rate Risk

Our long-term debt as of September 30, 2023 was comprised of borrowings that contain fixed and floating interest rates. The Senior Notes due 2028, Senior Notes due 2031, and Convertible Notes bear cash interest at fixed rates. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement (see Note 4 to our condensed financial statements).

Changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at September 30, 2023 would have cost us an additional $3.8 million in annual interest expense under our Revolving Credit Facility.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934, as amended ("Exchange Act"), reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

As of September 30, 2023, our management, including our principal executive officer and principal financial officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our principal executive officer and principal financial officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of September 30, 2023.

Changes in Internal Control over Financial Reporting

No change in our Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended September 30, 2023, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. *Legal Proceedings.*

Our Company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 1A. *Risk Factors.*

Except as described in our Quarterly Report on Form 10-Q filed with the SEC for the period ended June 30, 2023, there have been no material changes to the risk factors disclosed in the "Risk Factors" section of our Annual Report on Form 10-K filed with the SEC for the period ended December 31, 2022.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds.*

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) of our common stock during the quarter ended September 30, 2023.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs[1]
Month #1				
July 1, 2023 to July 31, 2023	—	$ —	—	$ 87.5 million
Month #2				
August 1, 2023 to August 31, 2023	—	$ —	—	$ 87.5 million
Month #3				
September 1, 2023 to September 30, 2023	—	$ —	—	$ 87.5 million
Total	—	$ —	—	$ 87.5 million

(1) In May 2022, the Company's Board of Directors approved and the Company promptly announced a stock repurchase program to acquire up to $150 million of shares of our outstanding common stock. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

Item 3. *Defaults Upon Senior Securities.*

None.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Item 5. *Other Information.*

(a) None.

(b) None.

(c) During the quarter ended September 30, 2023, no director or officer of the Companyadopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K.

During the quarter ended September 30, 2023, the Company did not adopt or terminate a “Rule 10b5-1 trading arrangement” as that term is defined in Item 408(a) of Regulation S-K.

Item 6. *Exhibits.*

Exhibit No.	Description	Reference
3.1	Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated August 24, 2018	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
3.2	Certificate of Amendment to the Restated Certificate of Incorporation of Northern Oil and Gas, Inc., dated September 18, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 24, 2020
3.3	Amended and Restated Bylaws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 20, 2023
10.1	Second Amendment to the Third Amended and Restated Credit Agreement among Northern Oil and Gas, Inc., Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, dated August 2, 2023.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 4, 2023
10.2	Termination Agreement, dated August 3, 2023, by and among Robert B. Rowling, Cresta Investments, LLC, Cresta Greenwood, LLC, TRT Holdings, Inc., Michael Frantz and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on August 4, 2023
31.1	Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
101.INS	Inline XBRL Instance Document	Filed herewith
101.SCH	Inline XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith
104	The cover page from Northern Oil and Gas, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2023, formatted in Inline XBRL and contained in Exhibit 101	Filed herewith

SIGNATURES

Pursuant to the requirements 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.

NORTHERN OIL AND GAS, INC.

Date:	November 2, 2023	By:	/s/ Nicholas O'Grady
			Nicholas O'Grady, Chief Executive Officer (on behalf of Registrant)
Date:	November 2, 2023	By:	/s/ Chad Allen
			Chad Allen, Chief Financial Officer and principal financial and accounting officer (on behalf of Registrant)

Exhibit 31.1

CERTIFICATION

I, Nicholas O’Grady certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

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(s) 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; and

   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; and

   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;

5. The registrant’s other certifying officer(s) 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 registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness 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.

Dated: November 2, 2023

By: /s/ Nicholas O’Grady

Nicholas O’Grady
Principal Executive Officer

Exhibit 31.2

CERTIFICATION

I, Chad Allen certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

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(s) 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; and

   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; and

   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;

5. The registrant's other certifying officer(s) 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 registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness 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.

Dated: November 2, 2023

By: /s/ Chad Allen

Chad Allen
Principal 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 Quarterly Report of Northern Oil and Gas, Inc., (the “Company”) on Form 10-Q for the quarterly period ended September 30, 2023, as filed with the United States Securities and Exchange Commission on the date hereof, (the “Report”), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: November 2, 2023

By: /s/ Nicholas O’Grady
Nicholas O’Grady
Principal Executive Officer

Dated: November 2, 2023

By: /s/ Chad Allen
Chad Allen
Principal Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.