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, 2020

☐ **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.)

601 Carlson Pkwy – Suite 990
Minnetonka, Minnesota 55305
(Address of Principal Executive Offices)

(952) 476-9800
(Registrant's Telephone Number)

N/A
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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	NYSE American

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 November 2, 2020, there were 45,851,326 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 and produce crude oil, NGLs, or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil, NGLs, or natural gas in another reservoir, or to extend 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.

"*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.

"*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:

"*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 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 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 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.

"*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.

(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 ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average 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.

"*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.

NORTHERN OIL AND GAS, INC.
FORM 10-Q

September 30, 2020

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, 2020	December 31, 2019
Assets	(Unaudited)	
Current Assets:		
Cash and Cash Equivalents	$ 1,803	$ 16,068
Accounts Receivable, Net	60,067	108,274
Advances to Operators	714	893
Prepaid Expenses and Other	1,697	1,964
Derivative Instruments	119,468	5,628
Income Tax Receivable	—	210
Total Current Assets	183,749	133,037
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	4,344,346	4,178,605
Unproved	10,328	11,047
Other Property and Equipment	2,215	2,157
Total Property and Equipment	4,356,889	4,191,809
Less – Accumulated Depreciation, Depletion and Impairment	(3,533,887)	(2,443,216)
Total Property and Equipment, Net	823,002	1,748,593
Derivative Instruments	6,826	8,554
Deferred Income Taxes	—	210
Acquisition Deposit	225	—
Other Noncurrent Assets, Net	11,722	15,071
Total Assets	$ 1,025,524	$ 1,905,465
Liabilities and Stockholders' Equity (Deficit)		
Current Liabilities:		
Accounts Payable	$ 20,372	$ 69,395
Accrued Liabilities	70,203	110,374
Accrued Interest	8,442	11,615
Derivative Instruments	5,438	11,298
Current Portion of Long-term Debt	65,000	—
Other Current Liabilities	1,000	795
Total Current Liabilities	170,455	203,477
Long-term Debt	918,327	1,118,161
Derivative Instruments	2,456	8,079
Asset Retirement Obligations	17,891	16,759
Other Noncurrent Liabilities	126	345
Total Liabilities	$ 1,109,255	$ 1,346,822
Commitments and Contingencies (Note 8)		

Stockholders' Equity (Deficit)		
Preferred Stock, Par Value $.001; 5,000,000 Shares Authorized; 2,218,732 Series A Shares Outstanding at 9/30/2020 1,500,000 Series A Shares Outstanding at 12/31/2019	2	2
Common Stock, Par Value $.001; 135,000,000* Shares Authorized; 45,556,326* Shares Outstanding at 9/30/2020 40,608,518* Shares Outstanding at 12/31/2019	448	406
Additional Paid-In Capital	1,554,053	1,431,438
Retained Deficit	(1,638,234)	(873,203)
Total Stockholders' Equity (Deficit)	(83,731)	558,643
Total Liabilities and Stockholders' Equity (Deficit)	$ 1,025,524	$ 1,905,465

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Revenues				
Oil and Gas Sales	$ 73,680	$ 157,989	$ 224,541	$ 440,519
Gain (Loss) on Commodity Derivatives, Net	(26,361)	75,892	277,582	(27,139)
Other Revenue	3	3	12	10
Total Revenues	47,322	233,883	502,135	413,389
Operating Expenses				
Production Expenses	24,159	32,347	88,132	83,146
Production Taxes	6,936	15,391	20,750	41,944
General and Administrative Expense	4,605	4,206	14,185	15,506
Depletion, Depreciation, Amortization and Accretion	30,786	55,566	129,350	146,791
Impairment of Other Current Assets	—	5,275	—	7,969
Impairment Expense	199,489	—	962,205	—
Total Operating Expenses	265,975	112,784	1,214,622	295,355
Income (Loss) From Operations	(218,653)	121,100	(712,487)	118,034
Other Income (Expense)				
Interest Expense, Net of Capitalization	(14,637)	(21,510)	(45,145)	(58,836)
Write-off of Debt Issuance Costs	(1,543)	—	(1,543)	—
Gain (Loss) on Unsettled Interest Rate Derivatives, Net	224	—	(1,205)	—
Gain (Loss) on Extinguishment of Debt, Net	1,592	—	(3,718)	(425)
Debt Exchange Derivative Gain/(Loss)	—	(23)	—	1,390
Contingent Consideration Loss	—	(5,262)	—	(28,633)
Other Income (Expense)	13	75	14	88
Total Other Income (Expense)	(14,351)	(26,719)	(51,597)	(86,416)
Income (Loss) Before Income Taxes	(233,004)	94,381	(764,084)	31,619
Income Tax Provision (Benefit)	—	—	(166)	—
Net Income (Loss)	$ (233,004)	$ 94,381	$ (763,918)	$ 31,619
Cumulative Preferred Stock Dividend	(3,718)	—	(10,986)	—
Net Income (Loss) Attributable to Common Shareholders	$ (236,722)	$ 94,381	$ (774,904)	$ 31,619
Net Income (Loss) Per Common Share – Basic*	$ (5.44)	$ 2.38	$ (18.53)	$ 0.83
Net Income (Loss) Per Common Share – Diluted*	$ (5.44)	$ 2.38	$ (18.53)	$ 0.83
Weighted Average Common Shares Outstanding – Basic*	43,517,074	39,604,482	41,812,553	38,204,403
Weighted Average Common Shares Outstanding – Diluted*	43,517,074	39,653,070	41,812,553	38,274,426

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

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

	Nine Months Ended September 30,	
(In thousands)	2020	2019
Cash Flows from Operating Activities		
Net Income (Loss)	$ (763,918)	$ 31,619
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization and Accretion	129,350	146,791
Amortization of Debt Issuance Costs	3,999	3,948
Write-off of Debt Issuance Costs	1,543	—
Loss on Extinguishment of Debt	3,718	425
Amortization of Bond Premium on Long-term Debt	(802)	(2,165)
Deferred Income Taxes	210	—
(Gain) Loss of Derivative Instruments	(123,595)	62,806
Gain on Debt Exchange Derivative	—	(1,390)
Loss on Contingent Consideration	—	28,633
PIK Interest on Second Lien Notes	—	1,742
Stock-Based Compensation Expense	3,182	4,280
Impairment of Other Current Assets	—	7,969
Impairment Expense	962,205	—
Other	(172)	(41)
Changes in Working Capital and Other Items:		
Accounts Receivable, Net	48,491	(6,589)
Prepaid and Other Expenses	268	1,674
Accounts Payable	(1,127)	1,058
Accrued Interest	(3,199)	2,813
Accrued Liabilities	(1,501)	6,916
Payment of Contingent Consideration	—	(21,164)
Net Cash Provided by Operating Activities	258,652	269,323
Cash Flows from Investing Activities		
Drilling and Development Capital Expenditures	(218,193)	(206,306)
Acquisition of Oil and Natural Gas Properties	(31,075)	(210,642)
Acquisition Deposit	(225)	—
Purchases of Other Property and Equipment	(59)	(1,001)
Net Cash Used for Investing Activities	(249,552)	(417,948)
Cash Flows from Financing Activities		
Advances on Revolving Credit Facility	56,000	313,000
Repayments on Revolving Credit Facility	(65,000)	(126,000)
Repurchases of Second Lien Notes	(13,514)	(10,488)
Debt Issuance Costs Paid	(447)	(328)
Debt Exchange Derivative Settlements	—	(1,044)
Contingent Consideration Settlements	—	(11,278)
Repurchases of Common Stock	—	(15,108)
Restricted Stock Surrenders - Tax Obligations	(404)	(584)
Net Cash (Used for) Provided by Financing Activities	(23,365)	148,169
Net Decrease in Cash and Cash Equivalents	(14,265)	(456)

Cash and Cash Equivalents - Beginning of Period	16,068	2,358
Cash and Cash Equivalents - End of Period	1,803	1,901

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, 2019	40,608,518	$ 406	1,500,000	$ 2	$ 1,431,438	$ (873,203)	$ 558,643
Issuance of Common Stock	5,000	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,263	—	1,263
Restricted Stock Surrenders - Tax Obligations	(33,200)	—	—	—	(396)	—	(396)
Issuance of Preferred Stock, Net of Issuance Costs	—	—	794,702	1	81,211	—	81,212
Net Income	—	—	—	—	—	368,286	368,286
March 31, 2020	40,580,318	$ 406	2,294,702	$ 2	$ 1,513,516	$ (504,917)	$ 1,009,007
Issuance of Common Stock	219,562	2	—	—	—	—	2
Restricted Stock Forfeitures	(271)	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	1,313	—	1,313
Restricted Stock Surrenders - Tax Obligations	(944)	—	—	—	(8)	—	(8)
Issuance under Debt Exchange Agreements	2,845,326	28	—	—	29,586	—	29,615
Net Loss	—	—	—	—	—	(899,200)	(899,200)
June 30, 2020	43,643,991	$ 436	2,294,702	$ 2	$ 1,544,407	$ (1,404,117)	$ 140,729
Issuance of Common Stock	66,025	—	—	—	—	—	—
Share Based Compensation	—	—	—	—	990	—	990
Issuance under Debt Exchange Agreements	1,319,615	6	—	—	7,548	—	7,554
Issuance under Series A Preferred Exchange Agreements	526,695	6	(75,970)	—	1,108	(1,113)	—
Net Loss	—	—	—	—	—	(233,004)	(233,004)
September 30, 2020	45,556,326	$ 448	2,218,732	$ 2	$ 1,554,053	$ (1,638,234)	$ (83,731)

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

(In thousands, except share data)	Common Stock* Shares	Common Stock* Amount	Preferred Stock Shares	Preferred Stock Amount	Additional Paid-In Capital	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
December 31, 2018	37,833,307	$ 378	—	$ —	$ 1,226,371	$ (796,884)	$ 429,865
Issuance of Common Stock	316,020	3	—	—	—	—	3
Restricted Stock Forfeitures	(480)	—	—	—	—	—	—
Stock-Based Compensation	—	—	—	—	2,832	—	2,832
Restricted Stock Surrenders - Tax Obligations	(22,053)	—	—	—	(558)	—	(558)
Repurchases of Common Stock	(563,500)	(6)	—	—	(15,102)	—	(15,108)
Contingent Consideration Settlements	116,754	1	—	—	2,886	—	2,887
Net Loss	—	—	—	—	—	(107,162)	(107,162)
March 31, 2019	37,680,048	$ 377	—	$ —	$ 1,216,429	$ (904,046)	$ 312,760
Issuance of Common Stock	900	—	—	—	—	—	—
Restricted Stock Forfeitures	(40,203)	—	—	—	—	—	—
Stock-Based Compensation	—	—	—	—	1,750	—	1,750
Restricted Stock Surrenders - Tax Obligations	(944)	—	—	—	(26)	—	(26)
Equity Offerings	—	—	—	—	—	—	—
Issuance under Debt Exchange Agreements	524,988	5	—	—	12,186	—	12,192
Contingent Consideration Settlements	778,811	8	—	—	18,567	—	18,575
Net Income	—	—	—	—	—	44,399	44,399
June 30, 2019	38,943,600	$ 389	—	$ —	$ 1,248,906	$ (859,647)	$ 389,649
Issuance of Common Stock	—	—	—	—	—	—	—
Restricted Stock Forfeitures	(4,560)	—	—	—	—	—	—
Stock-Based Compensation	—	—	—	—	(8)	—	(8)
Restricted Stock Surrenders - Tax Obligations	—	—	—	—	—	—	—
Equity Offerings	—	—	—	—	—	—	—
Issuance under Debt Exchange Agreements	198,553	2	—	—	3,541	—	3,543
Acquisition of Oil and Natural Gas Properties	560,215	6	—	—	11,703	—	11,708
Net Exercise of Stock Options	—	—	—	—	—	—	—
Repurchases of Common Stock	—	—	—	—	—	—	—
Contingent Consideration Settlements	736,840	7	—	—	14,833	—	14,841
Net Income	—	—	—	—	—	94,381	94,381
September 30, 2019	40,434,648	$ 404	—	$ —	$ 1,278,976	$ (765,266)	$ 514,114

*Adjusted for the 1-for-10 reverse stock split. See Note 5.

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

NOTES TO CONDENSED FINANCIAL STATEMENTS
SEPTEMBER 30, 2020
(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, exploitation, development and production of crude oil and natural gas properties. The Company's common stock trades on the NYSE American market under the symbol "NOG".

Northern's principal business is crude oil and natural gas exploration, development, and production with operations that primarily target the Bakken and Three Forks formations in the Williston Basin of 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, 2019 has been derived from the Company's audited financial statements for the year ended December 31, 2019. However, such information includes all adjustments (consisting of normal recurring adjustments and change in accounting principles) 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, 2019, which were included in the Company's 2019 Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

Reverse Stock Split

On September 18, 2020, the Company effected a 1-for-10 reverse stock split of its common stock. Unless otherwise noted, impacted amounts and share information included in the financial statements and notes thereto, and elsewhere in this Form 10-Q, have been retroactively adjusted as if the reverse stock split occurred on the first day of the first period presented. Certain amounts may be slightly different than previously reported due to the settlement of fractional shares as a result of the reverse stock split and rounding. See Note 5 below for more information regarding the reverse stock split.

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 oil and natural gas properties, asset retirement obligations and deferred income taxes. Actual results may differ from those estimates.

The Company considered the impact of the novel coronavirus 2019 ("COVID-19") pandemic on the assumptions and estimates used by management in the unaudited condensed financial statements for the reporting periods presented. As a result of the significant decline in current and expected future commodity prices, the Company recognized a material impairment charge during the three and nine months ended September 30, 2020 (see Note 3). Management's estimates and assumptions were based on historical data and consideration of future market conditions. Given the uncertainty inherent in any projection, which is heightened by the possibility of unforeseen additional impacts from the COVID-19 pandemic, 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 in the near term.

Adopted and Recently Issued Accounting Pronouncements

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-13, Financial Instruments - Credit Losses (Topic 326) - Measurement of credit losses on financial instruments, which requires a company immediately recognize management's current estimated credit losses ("CECL") for all financial instruments that are not accounted for at fair value through net income. Previously, credit losses on financial assets were only required to be recognized when they were incurred. The Company adopted ASU 2016-13 on January 1, 2020. The guidance did not have a significant impact on the condensed financial statements or notes accompanying the condensed financial statements.

In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (Topic 820) - Disclosure framework - Changes to the Disclosure Requirements for Fair Value Measurement, which modifies the disclosure requirements on fair value measurements in Topic 820. The Company adopted ASU 2018-13 on January 1, 2020. The guidance did not have a significant impact on the condensed financial statements or notes accompanying the condensed financial statements.

In December 2019, the FASB issued ASU 2019-12, Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes, which simplifies the accounting for income taxes by removing certain exceptions to the general principles and also simplification of areas such as separate entity financial statements and interim recognition of enactment of tax laws or rate changes. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, including interim reporting periods within those years. The Company is currently evaluating the effect of ASU 2019-12, but does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or result of operations.

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform, which provides temporary optional guidance to companies impacted by the transition away from the London Interbank Offered Rate (LIBOR). The amendment provides certain expedients and exceptions to applying GAAP in order to lessen the potential accounting burden when contracts, hedging
relationships, and other transactions that reference LIBOR as a benchmark rate are modified. This amendment is effective upon issuance and expires on December 31, 2022. The Company is currently assessing the impact of the LIBOR transition and this ASU on the Company's condensed financial statements.

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 oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of 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.

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, 2020 and 2019, 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 revenue sources, which are oil sales and natural gas and NGL sales, and the Company only has revenue fromone geographic area, the Williston Basin in the United States, primarily in North Dakota and Montana. Oil sales for the three months ended September 30, 2020 and 2019 were $70.6 million and $152.8 million, respectively. Natural gas and NGL sales for the three months ended September 30, 2020 and 2019 were $3.1 million and $5.2 million, respectively. Oil sales for the nine months ended September 30, 2020 and 2019 were $215.7 million and $416.3 million, respectively. Natural gas and NGL sales for the nine months ended September 30, 2020 and 2019 were $8.8 million and $24.3 million, respectively.

Concentrations of Market, Credit 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, economic disruptions resulting from the COVID-19 pandemic, 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 the current 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, 2020, the Company's top four operators made up48% and 49%, respectively, of total oil and gas sales, compared to 45% and 52% for the three and nine months ended September 30, 2019.

The Company faces concentration risk due to the fact that substantially all of its oil and natural gas properties are located in the Williston Basin, primarily in North Dakota and Montana. As a result, the Company is disproportionately exposed to risks affecting this geographic area of operations.

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 and vesting of restricted stock awards, and shares issuable upon conversion of the Series A Preferred Stock (see Note 5). The number of potential common shares outstanding are calculated using the treasury stock or if-converted method.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and nine months ended September 30, 2020 and 2019 are as follows:

(In thousands, except share and per share data)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Net Income (Loss)	$ (233,004)	$ 94,381	$ (763,918)	$ 31,619
Less: Cumulative Dividends on Preferred Stock	(3,718)	—	(10,986)	—
Net Income (Loss) Attributable to Common Stock	$ (236,722)	$ 94,381	$ (774,904)	$ 31,619
Weighted Average Common Shares Outstanding:				
Weighted Average Common Shares Outstanding – Basic	43,517,074	39,604,482	41,812,553	38,204,403
Plus: Dilutive Effect of Restricted Stock	—	48,588	—	70,023
Plus: Dilutive Effect of Preferred Shares	—	—	—	—
Weighted Average Common Shares Outstanding – Diluted	43,517,074	39,653,070	41,812,553	38,274,426
Net Income (Loss) per Common Share:				
Basic	$ (5.44)	$ 2.38	$ (18.53)	$ 0.83
Diluted	$ (5.44)	$ 2.38	$ (18.53)	$ 0.83
Shares Excluded from EPS Due to Anti-Dilutive Effect:				
Restricted Stock	84,319	8,821	54,885	4,033
Preferred Stock	10,057,601	—	9,880,344	—

Supplemental Cash Flow Information

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

(In thousands)	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Supplemental Cash Items:		
Cash Paid During the Period for Interest, Net of Amount Capitalized	$ 42,736	$ 52,916
Cash Paid During the Period for Income Taxes	—	—
Non-cash Operating Activities:		
Contingent Consideration Settlements in Excess of Acquisition-Date Liabilities	—	18,480
Non-cash Investing Activities:		
Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities	76,498	178,772
Capitalized Asset Retirement Obligations	457	3,703
Compensation Capitalized on Oil and Gas Properties	385	296
Issuance of Common Stock - Acquisitions of Oil and Natural Gas Properties	—	11,708
Issuance of Unsecured VEN Bakken Note	—	128,660
Non-cash Financing Activities:		
Issuance of 8.50% Second Lien Notes due 2023 - PIK Interest	—	3,480
Issuance of Common Stock for 2L Notes Repurchase	37,169	—
Issuance of Preferred Stock for 2L Notes Repurchase	81,212	—
Issuance of Common Stock for Preferred Stock Exchange	1,113	—
Debt Exchange Derivative Liability Settlements	—	15,735
Contingent Consideration Settlements	—	17,822

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.

As a result of low commodity prices and their effect on the proved reserve values of properties, the Company recorded a non-cash ceiling test impairment of $199.5 million and $962.2 million for the three and nine months ended September 30, 2020, respectively. The Company did not have any impairment of its proved oil and gas properties during 2019.

At September 30, 2020, the Company's impairment review used prices that reflect an average of the trailing 12-month prices as prescribed pursuant to the SEC's guidelines. The average prices used in the September 30, 2020 impairment review are significantly higher than the actual and currently forecasted prices for 2020. As lower average monthly pricing is reflected in the trailing 12-month average pricing calculation for future fiscal quarters, the present value of the Company's future net revenues is expected to decline and additional impairments are expected to be recognized. Given the current oil and natural gas pricing environment, the Company expects it will have additional noncash ceiling test write-downs of its oil and natural gas properties in 2020.

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. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

2020 Acquisitions

The Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $5.5 million and $12.9 million during the three and nine months ended September 30, 2020, respectively, excluding the associated development costs.

2019 Acquisitions

Not including the VEN Bakken Acquisition described below, the Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $9.9 million and $25.0 million during the three and nine months ended September 30, 2019, respectively, excluding the associated development costs.

VEN Bakken Acquisition

On July 1, 2019, the Company completed its acquisition (the "VEN Bakken Acquisition") of certain oil and gas properties and interests from VEN Bakken, LLC ("VEN Bakken"), effective as of July 1, 2019. VEN Bakken is a wholly-owned subsidiary of Flywheel Bakken, LLC. At closing the acquired assets consisted of approximately 90.1 net producing wells and 3.3 net wells in process, as well as approximately18,000 net acres substantially all in North Dakota. The Company also assumed certain crude oil derivative contracts from VEN Bakken as part of the acquisition. The VEN Bakken Acquisition was completed pursuant to the purchase and sale agreement between the Company and VEN Bakken, dated as of April 18, 2019.

The total estimated consideration paid by the Company was $315.3 million, consisting of (i) $174.9 million in cash, (ii) shares of Company common stock valued at $11.7 million, and (iii) $128.7 million of value attributable to a 6.0% unsecured promissory note due July 1, 2022 issued by the Company to VEN Bakken in the aggregate principal amount of $130.0 million (the "Unsecured VEN Bakken Note"). The Company incurred $1.8 million of transactions costs in connection with the acquisition, which are included in general and administrative expense in the condensed 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	$	324,974
Asset retirement cost		2,680
Total assets acquired		327,654
Asset retirement obligations		(2,680)
Derivative instruments		(9,694)
Net assets acquired	$	315,280
Fair value of consideration paid for net assets:		
Cash consideration	$	174,912
Issuance of common stock		11,708
Unsecured VEN Bakken Note		128,660
Total fair value of consideration transferred	$	315,280

Pro Forma Information

The following summarized unaudited pro forma condensed statement of operations information for the nine months ended September 30, 2019, assumes that the VEN Bakken Acquisition occurred as of January 1, 2019. There is no pro forma information included for the three and nine months ended September 30, 2020, or for the three months ended September 30, 2019, because the Company's actual financial results for such periods fully reflect this acquisition. 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 acquisition as of January 1, 2019, or that would be attained in the future.

(In thousands)		**Nine Months Ended September 30, 2019**
Revenues	$	441,716
Net Income		11,564

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 abandoned. 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, 2020 and 2019, unproved properties of $0.7 million and $0.8 million, respectively, were impaired. For the nine months ended September 30, 2020 and 2019, unproved properties of $2.7 million and $2.5 million, respectively, were impaired.

NOTE 4 LONG-TERM DEBT

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

(in thousands)	September 30, 2020	December 31, 2019
Revolving Credit Facility	$ 571,000	$ 580,000
Second Lien Notes due 2023	287,755	417,733
Unsecured VEN Bakken Note	130,000	130,000
Total principal	988,755	1,127,733
Unamortized debt discounts and premiums	2,276	4,860
Unamortized debt issuance costs[1]	(7,704)	(14,432)
Total debt	983,327	1,118,161
Less current portion of long-term debt	(65,000)	—
Total long-term debt	$ 918,327	$ 1,118,161

(1) Debt issuance costs related to the Company's revolving credit facility of $6.9 million and $9.8 million as of September 30, 2020 and December 31, 2019, respectively, are recorded in "Other Noncurrent Assets, Net" on the balance sheets. During the three and nine month periods ended September 30, 2020, the Company recorded a $1.5 million write-off of debt issuance costs as a result of the reduction in the borrowing base under the Revolving Credit Facility.

Revolving Credit Facility

On November 22, 2019, the Company entered into a Second Amended and Restated Credit Agreement (the "Revolving Credit Facility") with Wells Fargo Bank, National Association, as administrative 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 October 5, 2018. The Revolving Credit Facility is scheduled to mature on November 22, 2024, provided that the maturity date shall be 91 days prior to the scheduled maturity date of the earlier of (i) the Second Lien Notes (defined below) if any Second Lien Notes remain outstanding on such date or (ii) the Unsecured VEN Bakken Note if any principal amount of the Unsecured VEN Bakken Note remains outstanding on such date.

The Revolving Credit Facility 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. The borrowing base as of September 30, 2020 was $660.0 million. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim "wildcard" redetermination available between scheduled redeterminations. The April 1st scheduled redetermination shall be based on a January 1st engineering report audited by a third party (reasonably acceptable by the Agent). The most recent redetermination was completed on November 2, 2020, with the borrowing base reaffirmed at $660.0 million.

At the Company's option, borrowings under the Revolving Credit Facility shall bear interest at the base rate or LIBOR 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 LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 100 to 200 basis points, and the applicable margin for LIBOR loans ranges from 200 to 300 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, maintain excess cash liquidity, 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 pro forma 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 ASC 815, divided by consolidated current liabilities excluding current non-cash obligations under FASB ASC 815 and current maturities under the Revolving Credit Facility, the Second Lien Notes and the Unsecured VEN Bakken Note) shall not be less than 1.00 to 1.00. The Company is in compliance with these financial covenants as of September 30, 2020.

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 us or the Company's 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 than 90% 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.

Second Lien Notes due 2023

On May 15, 2018, the Company issued 8.500% senior secured second lien notes due 2023 (the "Second Lien Notes") with an aggregate principal amount of $344.3 million (the "Original 2L Notes") in exchange for certain previously outstanding 8.000% senior unsecured notes due June 1, 2020 (the "Unsecured Notes"). In October 2018, the Company issued an additional $350.0 million aggregate principal amount of Second Lien Notes (the "Additional 2L Notes"), the proceeds of which were used in connection with the retirement of the Company's prior term loan credit agreement. In addition, as of and through September 30, 2020, the Company had issued another $4.3 million of additional aggregate principal amount of Second Lien Notes pursuant to the interest payment-in-kind provisions thereof.

During 2019, the Company repurchased and retired $10.1 million in aggregate principal amount of Second Lien Notes in open market transactions. In November 2019, the Company completed a cash tender offer to redeem and repay $200.0 million principal amount of Second Lien Notes. Also in November 2019, the Company redeemed and repaid $70.8 million principal amount of Second Lien Notes in exchange for Series A Preferred Stock.

During the nine months ended September 30, 2020, the Company repurchased and retired $13.5 million aggregate principal amount of Second Lien Notes in open market transactions. In the first quarter of 2020, the Company completed four independent, separately negotiated purchase agreements to repurchase and retire $76.7 million aggregate principal amount of Second Lien Notes in exchange for Series A Preferred Stock and cash. In the second quarter of 2020, the Company completed five independent, separately negotiated exchange agreements to retire $30.2 million aggregate principal amount of Second Lien Notes in exchange for 2.8 million shares of common stock. In the third quarter of 2020, the Company completed two independent, separately negotiated exchange agreements to retire $9.5 million aggregate principal amount of Second Lien Notes in exchange for 1.3 million shares of common stock.

The terms of the Second Lien Notes include those stated in the Indenture entered into on May 15, 2018 by the Company and Wilmington Trust, National Association, as trustee (the "Original 2L Indenture"), as amended by the First Supplemental Indenture, dated September 18, 2018 (the "First Supplemental 2L Indenture"), the Second Supplemental Indenture, dated October 5, 2018 (the "Second Supplemental 2L Indenture"), and the Third Supplemental Indenture, dated November 22, 2019 (the “Third Supplemental 2L Indenture” and, together with the Original 2L Indenture, the First Supplemental 2L Indenture, and the Second Supplemental 2L Indenture, the “2L Indenture”).

The Second Lien Notes are the senior secured obligations of the Company and rank equal in right of payment to all existing and future senior indebtedness of the Company and its subsidiaries. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company, subject to certain exceptions. The Second Lien Notes will be guaranteed by all of the Company’s direct and indirect subsidiaries that guarantee indebtedness under any other indebtedness for borrowed money of the Company or any of the Company’s subsidiary guarantors. As of September 30, 2020, the Company did not have any subsidiaries. The Second Lien Notes will mature on May 15, 2023.

Interest on the Second Lien Notes accrues at a rate of 8.500% per annum payable in cash quarterly in arrears on the first day of each calendar quarter. Additional interest may accrue depending on the Company’s total debt to EBITDAX ratio as of each December 31st and June 30th, provided that any such additional interest would be payable in kind (the “PIK Interest”). No PIK Interest will accrue so long as the Company’s total debt to EBITDAX ratio remains below 2.50 to 1.00 as of each applicable measurement date. PIK Interest of 1.00% per annum will accrue if the Company’s total debt to EBITDAX ratio is less than 2.75 to 1.00 but equal to or greater than 2.50 to 1.00. PIK Interest of 2.00% per annum will accrue if the Company’s total debt to EBITDAX ratio is less than 3.00 to 1.00 but equal to or greater than 2.75 to 1.00. PIK Interest of 3.00% per annum will accrue if the Company’s total debt to EBITDAX ratio is greater than or equal to 3.00 to 1.00. No PIK Interest has accrued since March 31, 2019. Default interest will be payable in cash on demand at the then applicable interest rate plus 3.00% per annum.

The Company may redeem all or a portion of any of the Second Lien Notes at the following redemption prices during the following time periods (plus accrued and unpaid interest on the Second Lien Notes redeemed): (i) from and after May 15, 2018 until May 15, 2021, 104%, (ii) on and after May 15, 2021 until May 15, 2022, 102%, and (iii) on and after May 15, 2022, 100%. Subject to the terms of an intercreditor agreement, the Company is also required to offer to prepay the Second Lien Notes with 100% of the net cash proceeds of asset sales, casualty events and condemnations in excess of $20.0 million not required to be used to pay down the loans under the Revolving Credit Facility, subject to customary exclusions and reinvestment provisions. Mandatory prepayment offers will be subject to payment of the make whole premium and redemption price set forth above, as applicable.

If a change of control occurs, the Company will be required to offer to repurchase the Second Lien Notes at the repurchase price of 101% of the principal amount of repurchased Second Lien Notes (subject to the prepayment provisions of the Revolving Credit Facility). The Second Lien Notes contain negative covenants that limit the Company’s ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, make certain types of investments, amend other debt documents, and incur any additional debt on a subordinated or junior basis to the Revolving Credit Facility and on a senior basis to the Second Lien Notes. The Second Lien Notes do not include any financial maintenance covenants.

The obligations of the Company under the Second Lien Notes may be accelerated upon the occurrence of an Event of Default (as such term is defined in the 2L Indenture). Events of Default include customary events for a capital markets debt financing 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, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as such term is defined in the 2L Indenture).

Unsecured VEN Bakken Note

On July 1, 2019, in connection with the completion of the VEN Bakken Acquisition, the Company issued the Unsecured VEN Bakken Note in the original principal amount of $130.0 million (see Note 3 above). Fifty percent (50%) of the original principal amount of the Unsecured VEN Bakken Note is required to be repaid by the Company on or before January 1, 2021, and the remaining unpaid principal amount is required to be repaid by the Company on or before July 1, 2022, in each case together with all accrued but unpaid interest thereon. Interest, at a rate of 6.0% per annum, is due quarterly in arrears on the first day of each calendar quarter, commencing on October 1, 2019. The Unsecured VEN Bakken Note does not include any financial maintenance covenants and is unsecured.

The obligations of the Company under the Unsecured VEN Bakken Note may be accelerated, subject to certain grace and cure periods, upon the occurrence of an event of default. Events of default include customary events, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of certain affirmative or negative covenants, defaults on other indebtedness of the Company, and bankruptcy or insolvency related defaults. The Unsecured VEN Bakken Note contains negative covenants that limit the Company’s ability, among other things, to pay dividends, repurchase equity, incur additional indebtedness, sell assets, terminate or unwind certain derivatives contracts, change the nature of its business or operations and merge or consolidate. In addition, the Unsecured VEN Bakken Note is subject to a mandatory prepayment offer in connection with a change of control.

NOTE 5 COMMON AND PREFERRED STOCK

Common Stock

On September 18, 2020, the Company effected a 1-for-10 reverse stock split of the Company's issued and outstanding shares of common stock (the "Reverse Split"). The Company's common stock began trading on a split-adjusted basis when the market opened on September 21, 2020. As a result of the Reverse Split, every ten shares of the Company's issued and outstanding common stock automatically converted into one share of common stock, without any change in the par value per share. A total of 44,663,990 shares of common stock were issued and outstanding immediately after the Reverse Split became effective on September 18, 2020. No fractional shares were outstanding following the Reverse Split.

In connection with the Reverse Split, the number of authorized shares of the Company's common stock was reduced to135,000,000 shares of common stock, par value $0.001 per share. As of September 30, 2020, the Company had 45,556,326 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 Board of Directors. As of September 30, 2020, the Company had 2,218,732 shares of preferred stock issued and outstanding, all of which were shares of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock (the "Series A Preferred Stock").

The terms of the Series A Preferred Stock are set forth in the Certificate of Designations for the Series A Preferred Stock (the "Certificate of Designations"), as originally filed with the Delaware Secretary of State on November 22, 2019, and as amended thereafter. The Series A Preferred Stock ranks senior to the Company's common stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding-up. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the board of directors of the Company, cumulative dividends in cash, at a rate of 6.500% per annum on the sum of (i) the $100 liquidation preference per share of Series A Preferred Stock (the "Liquidation Preference") and (ii) all accumulated and unpaid dividends (if any), payable semi-annually in arrears on May 15 and November 15 of each year, commencing on May 15, 2020. As of September 30, 2020, no dividends had been declared or paid, and there were $12.5 million of accumulated dividends on the Series A Preferred Stock.

The Reverse Split did not affect the number of authorized or issued and outstanding shares of the Company's preferred stock, nor the liquidation per share preference. As a result of the Reverse Split and per the terms of the Certificate of Designations, the conversion rate for the Company's outstanding Series A Preferred Stock was automatically decreased to 4.363 shares of common stock for each share of Series A Preferred Stock (previously it was43.63 shares of common stock). The effect of the Reverse Split resulted in the Company recalculating its historical, basic and diluted EPS to reflect the 1-for-10 reverse stock split, effective September 18, 2020.

The Series A Preferred Stock is convertible at the holders' option (an "Optional Conversion") into common stock at a conversion rate set forth in the Certificate of Designations, subject to customary adjustments as provided for therein. As of September 30, 2020, the conversion rate was 4.363 shares of common stock for each share of Series A Preferred Stock (which is equivalent to a conversion price of approximately $22.92 per share of common stock). Holders may be entitled to additional shares of common stock or cash in connection with a conversion that occurs in connection with a Fundamental Change (as defined in the Certificate of Designations). The Series A Preferred Stock is convertible at the Company's option (a "Mandatory Conversion") if the closing sale price of the Company's common stock equals or exceeds 145% of the conversion price for at least 20 trading days (whether or not consecutive) in a period of30 consecutive trading days. A Mandatory Conversion would also entitle the holder to a cash payment equal to eight semi-annual dividend payments, less an amount equal to all cash dividend payments made in respect of such holder's shares of Series A Preferred Stock prior to such Mandatory Conversion. The occurrence of any Optional Conversion or Mandatory Conversion is subject to various terms and limitations set forth in the Certificate of Designations.

The Certificate of Designations also sets forth additional information relating to the payment of dividends, voting, conversion rights, consent rights, liquidation rights, the ranking of the Series A Preferred Stock in comparison with the Company's other securities, and other matters.

2020 Activity

Common Stock

During the nine months ended September 30, 2020,34,144 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 $0.4 million, which is based on the market prices on the dates the shares were surrendered.

During the nine months ended September 30, 2020, the Company issued4.2 million shares of common stock as part of separate exchange transactions pursuant to which the Company retired $39.7 million in aggregate principal amount of Second Lien Notes (see Note 4).

In September 2020, the Company issued 0.5 million shares of common stock in an exchange transaction pursuant to which the Company retired75,970 shares of Series A Preferred Stock.

Preferred Stock

During the nine months ended September 30, 2020, the Company issued794,702 shares of Series A Preferred Stock as part of separate transactions pursuant to which the Company retired $76.7 million in aggregate principal amount of Second Lien Notes (see Note 4).

As noted above, in September 2020, the Company retired75,970 shares of Series A Preferred stock in an exchange transaction pursuant to which the Company issued 0.5 million shares of common stock.

Stock Repurchase Program

In May 2011, 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 three and nine months ended September 30, 2020, the Company didnot repurchase shares of its common stock under the stock repurchase program. During the nine months ended September 30, 2019, the Company repurchased 0.6 million shares of its common stock under the stock repurchase program at a total cost of $16.3 million, of which $1.2 million was recorded as a settlement of contingent consideration liabilities. 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 now included in the Company's pool of authorized but unissued shares.

NOTE 6 STOCK-BASED COMPENSATION

The Company maintains its 2018 Equity Incentive Plan (the "2018 Plan"), which replaced the Company's prior 2013 Incentive Plan (the "2013 Plan"), for making equity-based awards to employees, directors and other eligible persons. No future awards will be made under the 2013 Plan. The 2013 Plan continues to govern awards that were made thereunder, which remain in effect pursuant to their terms. As of September 30, 2020, there were 971,055 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" 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 on the unaudited balance sheets.

The 2018 Plan and 2013 Plan award types 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, provided that any performance and/or market conditions are also met. RSAs issued to directors generally vest over one year, 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 with both service and performance conditions is recognized on a graded basis only 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.

In connection with the Reverse Split (see Note 5), the Company reduced the number of shares of common stock available for issuance under the Company's equity incentive plans in proportion to the Reverse Split ratio of 1-for-10. The Reverse Split also reduced the number of shares of common stock issuable upon the vesting of its RSAs in proportion to the Reverse Split ratio of 1-for-10 and caused a proportionate increase in share-based performance criteria applicable to such awards. The Reverse Split has no impact on Net Income (Loss) or total Stockholders' Equity as of, and for the three and nine months ended September 30, 2020 and 2019.

The following table reflects the outstanding RSAs and activity related thereto for the nine months ended September 30, 2020:

	Service-based Awards		Service and Performance-based Awards		Service and Market-based Awards		Service, Performance, and Market-based Awards	
	Number of Shares	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**	**Number of Shares**	**Weighted-average Grant Date Fair Value**
Outstanding at December 31, 2019	41,398	$ 24.10	37,500	$ 27.00	118,962	$ 18.00	70,800	$ 9.80
Shares granted	290,579	9.41	—	—	—	—	—	—
Shares forfeited	(271)	24.50	—	—	—	—	—	—
Shares vested	(177,302)	10.15	(21,250)	27.00	(6,917)	16.70	(31,600)	9.80
Outstanding at September 30, 2020	154,404	$ 12.48	16,250	$ 27.00	112,045	$ 18.13	39,200	$ 9.80

At September 30, 2020, there was $2.6 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 0.92 years. For the nine months ended September 30, 2020 and 2019, the total fair value of the Company's restricted stock awards vested was $1.9 million and $3.9 million, respectively.

NOTE 7 RELATED PARTY TRANSACTIONS

On October 21, 2019, the Company announced the commencement of (i) a cash tender offer (the "Tender Offer") to purchase up to $200.0 million in aggregate principal amount of the Company's Second Lien Notes; (ii) an exchange offer (the "Exchange Offer") to eligible holders of Second Lien Notes to exchange up to $70.8 million in aggregate principal amount of Second Lien Notes for shares of the Company's newly issued Series A Preferred Stock; (iii) a related solicitation of consents (the "Consent Solicitation") to adopt certain proposed amendments to the indenture for the Second Lien Notes; and (iv) an offer to eligible holders of Second Lien Notes to subscribe to purchase for up to $75.0 million in cash additional shares of Series A Preferred Stock (the "Subscription Offer"). Parties affiliated with TRT Holdings, Inc. (collectively, the "TRT Parties") held

Second Lien Notes and thus had the right to participate in the Tender Offer, Exchange Offer, Consent Solicitation and Subscription Offer on terms identical to the terms generally offered to all holders of Second Lien Notes. These transactions closed on November 22, 2019, with the TRT Parties (i) exchanging $1.0 million aggregate principal amount of Second Lien Notes for 10,947 shares of Series A Preferred Stock pursuant to the Exchange Offer and (ii) acquiring 10,947 additional shares of Series A Preferred Stock for a purchase price of $1.1 million pursuant to the Subscription Offer. On February 20, 2020, the Company entered into an exchange agreement (the "Exchange Agreement") with the TRT Parties related to the Series A Preferred Stock, as follows. The certificate of designations of the Series A Preferred Stock, as amended (the "Certificate of Designations"), contains limitations on the ability of the company or holders of Series A Preferred Stock to effect conversions of shares of Series A Preferred Stock for shares of the Company's common stock if after a conversion a holder would beneficially own shares of common stock in excess of 9.99% of the aggregate number of shares of the Company's common stock outstanding immediately after giving pro forma effect to the issuance of shares upon such conversion (the "Conversion Cap"). As of the date of the Exchange Agreement, the TRT Parties collectively beneficially owned a number of shares of the Company's common stock in excess of the Conversion Cap. The Exchange Agreement provides, notwithstanding anything to the contrary in the Certificate of Designations, including the Conversion Cap, for the TRT Parties to be able to exchange shares of Series A Preferred Stock for shares of the Company's common stock in the manner otherwise contemplated by the Certificate of Designations. As of the date hereof, the TRT Parties have not exchanged or converted any shares of Series A Preferred Stock into common stock. Two of our directors, Mr. Frantz and Mr. Popejoy, are employed by the TRT Parties and the TRT Parties beneficially owned in excess of 10% of the Company's outstanding common stock at the time of the transactions described in this paragraph.

In January 2019, the Company repurchased 0.4 million shares of Company common stock from W Energy Partners LLC ("W Energy") for cash consideration of $1.1 million. The repurchased shares were originally issued by the Company as partial consideration for an acquisition of oil and gas properties from W Energy during 2018. W Energy beneficially owned in excess of 10% of the Company's outstanding common stock at the time of the repurchase transactions.

The Company's Audit Committee is responsible for approving all transactions involving related parties, including each of the transactions identified above.

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.

The Company's interests in certain crude oil and natural gas leases from the State of North Dakota are subject to an ongoing dispute over the ownership of minerals underlying the bed of the Missouri River within the boundaries of the Fort Berthold Reservation. The ongoing dispute is between the State of North Dakota and three affiliated tribes, both of whom have purported to lease mineral rights in tracts of riverbed within the reservation boundaries. In the event the ongoing dispute results in a final judgment that is adverse to the Company's interests, the Company would be required to reverse approximately $4.4 million in revenue (net of accrued taxes) that has been accrued since the first quarter of 2013 based on the Company's purported interest in the crude oil and natural gas leases at issue. Due to the long-term nature of this title dispute, the $4.4 million in accounts receivable is included in "Other Noncurrent Assets, Net" on the condensed balance sheets. The Company fully maintains the validity of its interests in the crude oil and natural gas leases.

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, 2020 and 2019 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income due to the recognition of a full valuation allowance during both the three and nine months ended September 30, 2020 and 2019, respectively.

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. At September 30, 2020 and December 31, 2019, the Company maintains a full valuation allowance on its net DTAs.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security (CARES) Act was signed into law making several changes to the Internal Revenue Code. The changes include, but are not limited to: increasing the limitation on the amount of deductible interest expense, allowing companies to carryback certain net operating losses, and increasing the amount of net operating loss carryforwards that corporations can use to offset taxable income. The tax law changes in the Act did not have a material impact on the Company's income tax provision.

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, 2020 and December 31, 2019:

	Fair Value Measurements at September 30, 2020 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 Asset	$ —	$ 119,468	$ —
Commodity Derivatives – Noncurrent Asset	—	6,826	—
Commodity Derivatives – Current Liabilities	—	(4,908)	—
Commodity Derivatives – Noncurrent Liabilities	—	(1,781)	—
Interest Rate Derivatives – Current Liabilities	—	(530)	—
Interest Rate Derivatives – Noncurrent Liabilities	—	(675)	—
Total	$ —	$ 118,401	$ —

(In thousands)	Fair Value Measurements at December 31, 2019 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 Asset	$ —	$ 5,628	$ —
Commodity Derivatives – Current Liabilities	—	(11,298)	—
Commodity Derivatives – Noncurrent Asset	—	8,554	—
Commodity Derivatives – Noncurrent Liabilities	—	(8,079)	—
Total	$ —	$ (5,195)	$ —

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 on 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 LIBOR 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 on the condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

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 on the balance sheets, as it is recorded at carrying value, net of unamortized debt issuance costs and unamortized premium or discount (see Note 4). The fair value of the Company's Second Lien Notes is $241.7 million and $434.4 million at September 30, 2020 and December 31, 2019, respectively. The fair value of the Company's Second Lien Notes are based on active market quotes, which represent Level 1 inputs.

There is no active market for the Revolving Credit Facility or the Unsecured VEN Bakken Note. The recorded value of the Revolving Credit Facility approximates its fair value because of its floating rate structure based on the LIBOR spread, secured interest, and the Company's borrowing base utilization. The recorded fair value of the VEN Bakken Note is based primarily on estimated current rates available to us for debt of the same remaining duration and adjusted for nonperformance risk and credit risk (see Note 3). The fair value of the Unsecured VEN Bakken Note is $132.0 million and $130.0 million at September 30, 2020 and December 31, 2019, respectively. The fair value measurements for the Revolving Credit Facility and the Unsecured VEN Bakken Note represent Level 2 inputs.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of ASC 410. 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, 2020 were approximately $0.5 million.

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, 2020.

NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity price swaps, basis swaps, swaptions and collars (purchased put options and written call options) 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 on 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 on the balance sheet and the non-current asset and liability are netted on 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)	**2020**	**2019**	**2020**	**2019**
Gain on Settled Commodity Derivatives	$ 43,837	$ 18,386	$ 152,782	$ 35,666
Gain (Loss) on Unsettled Commodity Derivatives	(70,198)	57,506	124,800	(62,806)
Gain (Loss) on Commodity Derivatives, Net	$ (26,361)	$ 75,892	$ 277,582	$ (27,139)

The following table summarizes open commodity derivative positions as of September 30, 2020, for commodity derivatives that were entered into through September 30, 2020, for the settlement period presented:

	2020	2021	2022	2023
Oil:				
WTI NYMEX - Swaps:				
Volume (Bbl)	2,372,362	7,808,624	365,000	—
Weighted-Average Price ($/Bbl)	$ 58.03	$ 54.67	$ 50.05	$ —
WTI NYMEX - Swaptions[(1)]:				
Volume (Bbl)	—	318,250	3,131,125	1,095,000
Weighted-Average Price ($/Bbl)	$ —	$ 57.84	$ 52.68	$ 46.59
Natural Gas:				
Henry Hub NYMEX - Swaps:				
Volume (MMBtu)	2,760,000	13,000,000	1,825,000	—
Weighted-Average Price ($/MMBtu)	$ 2.44	$ 2.50	$ 2.53	$ —
Waha Inside FERC to Henry Hub - Basis Swaps:				
Volume (MMBtu)	—	69,000	—	—
Weighted-Average Differential ($/MMBtu)	$ —	$ (0.28)	$ —	$ —

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

Interest Rate Derivative Instruments

The Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of September 30, 2020, the Company had interest rate swaps with a total notional amount of $200.0 million. 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, 2020 and December 31, 2019, respectively. Certain amounts may be presented on a net basis on the condensed financial statements when such amounts are with the same counterparty and subject to a master netting arrangement.

Type of Contract	Balance Sheet Location		September 30, 2020 Estimated Fair Value		December 31, 2019 Estimated Fair Value
Derivative Assets:			*(In thousands)*		
Commodity Price Swap Contracts	Current Assets	$	119,468	$	20,164
Interest Rate Swap Contracts	Current Assets		—		—
Commodity Price Swap Contracts	Noncurrent Assets		6,826		16,069
Interest Rate Swap Contracts	Noncurrent Assets		—		—
Total Derivative Assets		$	126,294	$	36,233
Derivative Liabilities:					
Commodity Price Swap Contracts	Current Liabilities	$	(4,908)	$	(25,834)
Interest Rate Swap Contracts	Current Liabilities		(530)		—
Commodity Price Swap Contracts	Noncurrent Liabilities		(1,781)		(5,273)
Interest Rate Swap Contracts	Noncurrent Liabilities		(675)		—
Commodity Price Swaptions Contracts	Noncurrent Liabilities		—		(10,321)
Total Derivative Liabilities		$	(7,894)	$	(41,428)

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 on the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected on the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

	Estimated Fair Value at September 30, 2020					
(In thousands)		Gross Amounts of Recognized Assets (Liabilities)		Gross Amounts Offset on the Balance Sheet		Net Amounts of Assets (Liabilities) Presented in the Balance Sheet
Offsetting of Derivative Assets:						
Current Assets	$	122,167	$	(2,699)	$	119,468
Noncurrent Assets		17,166		(10,340)		6,826
Total Derivative Assets	$	139,333	$	(13,039)	$	126,294
Offsetting of Derivative Liabilities:						
Current Liabilities	$	(5,438)	$	—	$	(5,438)
Noncurrent Liabilities		(15,495)		13,039		(2,456)
Total Derivative Liabilities	$	(20,933)	$	13,039	$	(7,894)

(In thousands)	Estimated Fair Value at December 31, 2019 Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ 20,164	$ (14,536)	$ 5,628
Non-Current Assets	16,069	(7,515)	8,554
Total Derivative Assets	$ 36,233	$ (22,051)	$ 14,182
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (25,834)	$ 14,536	$ (11,298)
Non-Current Liabilities	(15,594)	7,515	(8,079)
Total Derivative Liabilities	$ (41,428)	$ 22,051	$ (19,377)

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, 2020. 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, 2020 and December 31, 2019.

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

Cautionary Statement Concerning Forward-Looking Statements

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding future events and our future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). 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, 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 sales, market size, collaborations, 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 control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: the effects of the COVID-19 pandemic and related economic slowdown, changes in crude oil and natural gas prices, the pace of drilling and completions activity on our current properties, infrastructure constraints and related factors affecting our properties, ongoing legal disputes over and potential shutdown of the Dakota Access Pipeline, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which we conduct business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, our ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, health-related epidemics, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting our company's 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 achieved may differ materially from expected results described in these statements. 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, 2019, 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. Forward-looking statements speak only as of the date they are made. We do not undertake, and specifically disclaim, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

The following discussion should be read in conjunction with the unaudited Condensed Financial Statements and accompanying Notes to Condensed Financial Statements appearing elsewhere in this report.

Overview

We are a company with a primary strategy of investing in non-operated minority working and mineral interests in oil and gas properties, with a core area of focus in the Williston Basin Bakken and Three Forks play in North Dakota and Montana. Using this strategy, we had participated in 6,354 gross (468.8 net) producing wells as of September 30, 2020. As of September 30, 2020, we had leased approximately 183,222 net acres, of which approximately 90% were developed and substantially all were located in the Williston Basin in North Dakota and Montana.

Our average daily production in the third quarter of 2020 was approximately 29,051 Boe per day, of which approximately 77% was oil. This was a 22% increase in production compared to the second quarter of 2020, primarily due to the return of shut-in and curtailed production and new wells added to production. Production in the second quarter of 2020 had decreased by 46% compared to the first quarter of 2020, driven by widespread shut-ins and curtailments of production and deferral of completion and development activity by operators in response to the drastic decline in crude oil prices during the first and second quarters of 2020. During the three months ended September 30, 2020, we added 3.4 net wells to production, compared to 1.3 net wells added to production in the second quarter of 2020 and 7.3 net wells added to production in the first quarter of 2020.

Reverse Stock Split

On September 18, 2020, we effected a 1-for-10 reverse stock split of the Company's issued and outstanding shares of common stock (the "Reverse Stock Split"). References to numbers of shares of common stock and per share data have been adjusted to reflect the Reverse Stock Split on a retroactive basis. See Note 5 to our condensed financial statements for further information.

Impacts of COVID-19 Pandemic and Current Economic Environment

The novel coronavirus disease (COVID-19) and efforts to mitigate the spread of the disease have created unprecedented challenges for our industry, including a drastic decline in demand for crude oil. In addition, in March 2020, members of OPEC failed to agree on production levels which led to a substantial decrease in oil prices and an increasingly volatile market. The oil price war ended in April 2020, with a deal to cut global petroleum output but did not go far enough to offset the impact of COVID-19 on demand. As a result of lower demand caused by the COVID-19 pandemic and the oversupply of crude oil, spot and future prices of crude oil fell to historic lows during the second quarter of 2020 and remain depressed. Operators in the Williston Basin responded by significantly decreasing drilling and completion activity, and by shutting in or curtailing production from a significant number of producing wells. Operators' decisions on these matters are evolving rapidly, and it remains extremely difficult to predict the future effects on our company and its business. See "Market Conditions" below.

As a result of these factors, we reduced our 2020 capital spending forecast to a range of $175.0 – $200.0 million, a reduction of 53% – 59% compared to our actual developmental capital expenditures in 2019. We also anticipate that our 2020 production will be significantly lower than originally expected due to actions by many of our operating partners to shut-in or curtail production and defer development plans as a result of the low commodity price environment. We estimate that curtailments, shut-ins and delayed well completions reduced our average daily production by approximately 16,800 Boe per day in the second quarter of 2020 and by approximately 11,000 Boe per day in the third quarter of 2020. Notwithstanding these reductions, which we expect to continue to some extent for the remainder of 2020 and into 2021, we still expect to generate significant cash flow in 2020 due to our crude oil and natural gas derivative positions and reduction in capital expenditures. We expect that this cash flow and borrowing availability under our revolving credit facility will allow us to meet our liquidity needs for at least the next twelve 12 months, including the $65.0 million principal payment on the Unsecured VEN Bakken Note that is due January 1, 2021.

At September 30, 2020, we performed an impairment review using prices that reflect an average of the trailing 12-month prices as prescribed pursuant to the SEC's guidelines and incurred a full-cost ceiling test impairment charge of $199.5 million for the three months ended September 30, 2020. In total, we have incurred full-cost ceiling test impairment charges of $962.2 million for the nine months ended September 30, 2020. The average prices used in the September 30, 2020 impairment review are significantly higher than the actual and currently forecasted prices for the remainder of 2020. If the current pricing environment persists, and as a result lower average monthly pricing is reflected in the trailing 12-month average pricing calculation, the present value of our future net revenues is expected to decline and additional full-cost ceiling impairment charges are expected to be recognized. This impairment charge would be non-cash in nature and should not impact any covenants under our various debt instruments. See Note 3 to our condensed financial statements.

In response to the COVID-19 pandemic, we have instituted various measures to protect our workforce and our business operations, such as remote working and business travel restrictions. As a non-operator with no field operations, substantially all of our employees' work can be completed from home. We will continue to monitor the guidelines and recommendations provided by the relevant authorities, and we will continue to make decisions aimed at protecting and furthering the interests of all stakeholders.

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 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

- *Oil price differentials*. The price differential between our well head price and the NYMEX WTI benchmark price is primarily driven by the cost to transport oil via train, pipeline or truck to refineries.

- *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 impairment.* Depreciation, depletion, amortization and impairment 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.

- *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 full 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 the price of oil;

- 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 Basin subjects our operating results to factors specific to this region. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, and the limitations of the developing infrastructure and transportation capacity in this region.

The price of oil in the Williston Basin can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market. Light sweet crude from the Williston Basin has a higher value at many major refining centers because of its higher quality relative to heavier and sour grades of oil; however, because of the Williston Basin's location relative to traditional oil transport centers, this higher value is generally offset to some extent by higher transportation costs. While rail transportation has historically been more expensive than pipeline transportation, Williston Basin's prices have at times justified shipment by rail to markets across the United States. Additional pipeline infrastructure has increased takeaway capacity in the Williston Basin which has improved wellhead values in the region, specifically the Dakota Access Pipeline ("DAPL") which has given the region low-cost transportation with access to Gulf Coast markets, which generally have higher benchmark pricing than WTI prices, offsetting some of the additional cost for the mode and increased distance of transportation.

The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX and the sales prices we receive for our oil production. Our oil price differential to the NYMEX benchmark price during the third quarter of 2020 was $6.54 per barrel, as compared to $5.48 per barrel in the third quarter of 2019. Fluctuations in our oil price differential are due to several factors such as takeaway capacity relative to production levels in the Williston Basin, regional storage capacity, and seasonal refinery maintenance temporarily depressing crude demand.

DAPL is subject to highly publicized ongoing litigation (the "DAPL Litigation") that could threaten its continued operation. In July 2020, a federal district court ordered DAPL to be shut down no later than August 6, 2020, pending the completion of an environmental impact statement ("EIS") that is expected to take at least a year to complete. The district court's shut-down order was subsequently temporarily stayed by a federal circuit court of appeals, and DAPL currently remains operational. But a court-ordered shut-down remains possible, and there is no guarantee that DAPL will be permitted to resume or continue operations following the completion of the EIS and/or the DAPL Litigation. During any period that DAPL is forced to shut down, we expect our average oil price differential to increase, although it is difficult to predict with any precision what effect this would have.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in oil prices that can substantially impact the level of drilling activity in the Williston Basin. 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. During the first nine months of 2020, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $7.5 million, compared to $8.0 million for the wells we elected to participate in during 2019.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Being primarily an oil producer, 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 adversely 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.

During the first half of 2020, the oil and natural gas industry witnessed an abrupt and significant decline in oil prices from $63 per Bbl in early January to an average of $27.95 per Bbl during the second quarter of 2020. This sudden decline in oil prices was attributable to two primary factors: (1) the precipitous decline in global oil demand resulting from the worldwide spread of COVID-19 and (2) a sudden, unexpected increase in global oil supply resulting from actions initiated by Saudi Arabia to increase its oil production to world markets following the failure of efforts by members of OPEC+ to agree on coordinated production cuts in March 2020. The OPEC price war ended in April 2020, with a deal to cut global petroleum output but did not go far enough to offset the dramatic negative impact of COVID-19 on demand. Oil prices improved in the third quarter compared to the second quarter, but the general outlook for the oil and natural gas industry remains highly uncertain, and we can provide no assurances as to when the economic disruptions resulting from COVID-19 and the corresponding decline in oil demand may begin to improve. Until such time, however, we anticipate that oil prices will remain well below the prices realized in 2019.

Prices for various quantities of oil, natural gas, and NGLs 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, 2020 and 2019.

	Three Months Ended September 30,	
	2020	**2019**
Average NYMEX Prices[(1)]		
Natural Gas (per Mcf)	$ 1.97	$ 2.38
Oil (per Bbl)	$ 40.90	$ 56.41

	Nine Months Ended September 30,	
	2020	**2019**
Average NYMEX Prices[(1)]		
Natural Gas (per Mcf)	$ 1.86	$ 2.62
Oil (per Bbl)	$ 38.12	$ 57.08

(1) Based on average NYMEX closing prices.

For the three months ended September 30, 2020, the average NYMEX pricing was $40.90 per barrel of oil, or 28% lower than the average NYMEX price per barrel for the comparable period in 2019. Our realized oil price after reflecting settled commodity derivatives was 3% lower in the third quarter of 2020 than in the third quarter of 2019 due to the aforementioned lower average NYMEX price per barrel and a higher oil price differential, partially offset by the gain on settled commodity derivatives.

For the three months ended September 30, 2020, the average NYMEX pricing was $1.97 per Mcf of natural gas, or 17% lower than the average NYMEX price per Mcf for the comparable period in 2019. Our realized natural gas and NGL price after reflecting settled commodity derivatives was $0.96 per Mcf in the third quarter of 2020 compared to $1.15 per Mcf in the third quarter of 2019.

As of September 30, 2020, we had a total volume on open crude oil price swaps of 10.5 million barrels at a weighted average price of approximately $55.26 per barrel. As of September 30, 2020, we had a total volume on open natural gas price swaps of 17.6 million MMbtu at a weighted average price of approximately $2.50 per MMbtu. See Note 11 to the condensed financial statements.

Results of Operations for the Three Months Ended September 30, 2020 and September 30, 2019

The following table sets forth selected operating data for the periods indicated.

	Three Months Ended September 30,		
	2020	2019	% Change
Net Production:			
Oil (Bbl)	2,054,847	3,002,789	(32) %
Natural Gas and NGLs (Mcf)	3,706,853	4,496,860	(18) %
Total (Boe)	2,672,656	3,752,266	(29) %
Net Sales (in thousands):			
Oil Sales	$ 70,595	$ 152,836	(54) %
Natural Gas and NGL Sales	3,085	5,153	(40) %
Gain on Settled Commodity Derivatives	43,838	18,386	
Gain (Loss) on Unsettled Commodity Derivatives	(70,198)	57,506	
Other Revenue	2	3	
Total Revenues	47,321	233,883	
Average Sales Prices:			
Oil (per Bbl)	$ 34.36	$ 50.90	(33) %
Effect of Gain on Settled Oil Derivatives on Average Price (per Bbl)	21.11	6.12	
Oil Net of Settled Oil Derivatives (per Bbl)	55.47	57.02	(3) %
Natural Gas and NGLs (per Mcf)	0.83	1.15	(28) %
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.13	—	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	0.96	1.15	(17) %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	27.57	42.10	(35) %
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	16.40	4.90	
Realized Price on a Boe Basis Including Settled Commodity Derivatives	43.97	47.00	(6) %
Operating Expenses (in thousands):			
Production Expenses	$ 24,159	$ 32,347	(25) %
Production Taxes	6,936	15,391	(55) %
General and Administrative Expenses	4,605	4,206	9 %
Depletion, Depreciation, Amortization and Accretion	30,786	55,566	(45) %
Costs and Expenses (per Boe):			
Production Expenses	$ 9.04	$ 8.62	5 %
Production Taxes	2.60	4.10	(37) %
General and Administrative Expenses	1.72	1.12	54 %
Depletion, Depreciation, Amortization and Accretion	11.52	14.81	(22) %
Net Producing Wells at Period End	468.8	444.0	6 %

Oil and Natural Gas Sales

In the third quarter of 2020, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, decreased 53% as compared to the third quarter of 2019, driven by a 35% decrease in realized prices, excluding the effect of settled commodity derivatives, and a 29% decrease in production. The lower average realized price in the third quarter of 2020 as compared to the same period in 2019 was partially driven by lower average NYMEX oil prices and a higher oil price differential. Oil price differential during the third quarter of 2020 was $6.54 per barrel, as compared to $5.48 per barrel in the third quarter of 2019. The lower average realized price in the third quarter of 2020 as compared to the same period in 2019 was also driven by a 28% decrease in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the third quarter of 2020 compared to the same period of 2019. See "Market Conditions" above.

Curtailments, shut-ins and completion delays due to the significant decline in commodity prices drove our 29% decrease in production levels in the third quarter of 2020 compared to the same period in 2019. See "Impacts of COVID-19 Pandemic and Current Economic Environment" above.

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 $26.4 million in the third quarter of 2020, compared to a gain of $75.9 million in the third quarter of 2019. 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 2020, we realized a gain on settled commodity derivatives of $43.8 million, compared to a $18.4 million gain in the third quarter of 2019. The increase in the gain on settled derivatives was primarily due to a significant decrease in the average NYMEX oil price in the third quarter of 2020 compared to the same period of 2019. During the third quarter of 2020, our derivative settlements included 2.1 million barrels of oil at an average settlement price of $58.42 per barrel. During the third quarter of 2019, our commodity derivative settlements included 2.4 million barrels of oil at an average settlement price of $61.89 per barrel. The average NYMEX oil price for the third quarter of 2020 was $40.90 compared to $56.41 for the third quarter of 2019. Our average realized price (including all commodity derivative cash settlements) in the third quarter of 2020 was $43.97 per Boe compared to $47.00 per Boe in the third quarter of 2019. The gain on settled derivatives increased our average realized price per Boe by $16.40 in the third quarter of 2020 and by $4.90 in the third quarter of 2019.

Unsettled commodity derivative gains and losses was a loss of $70.2 million in the third quarter of 2020, compared to a gain of $57.5 million in the third quarter of 2019. 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, 2020, all of our derivative contracts are recorded at their fair value, which was a net asset of $118.4 million, an increase of $123.6 million from the $5.2 million net liability recorded as of December 31, 2019. The increase in the net asset at September 30, 2020 as compared to December 31, 2019 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2019.

Production Expenses

Production expenses were $24.2 million in the third quarter of 2020, compared to $32.3 million in the third quarter of 2019. On a per unit basis, production expenses increased from $8.62 per Boe in the third quarter of 2019 to $9.04 per Boe in the third quarter of 2020 due in large part to a 29% decrease in our production volumes. On an absolute dollar basis, the decrease in our production expenses in the third quarter of 2020, as compared to the third quarter of 2019, was primarily due to a 29% decrease in production levels which was partially offset by a 6% 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 $6.9 million in the third quarter of 2020 compared to $15.4 million in the third quarter of 2019. The decrease is due to lower realized prices and lower production levels, which decreased our oil and natural gas sales in the third quarter of 2020 as compared to the third quarter of 2019. As a percentage of oil and natural gas sales, our production taxes were 9.4% and 9.7% in the third quarter of 2020 and 2019, respectively.

General and Administrative Expenses

General and administrative expenses were $4.6 million in the third quarter of 2020 compared to $4.2 million in the third quarter of 2019. The increase was primarily due to changes in compensation expense and the timing of other expenditures.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $30.8 million in the third quarter of 2020, compared to $55.6 million in the third quarter of 2019. Depletion expense, the largest component of DD&A, decreased by $24.8 million in the third quarter of 2020 compared to the third quarter of 2019. The aggregate decrease in depletion expense was driven by a 29% decrease in production levels coupled with a 23% decrease in the depletion rate per Boe. On a per unit basis, depletion expense was $11.38 per Boe in the third quarter of 2020 compared to $14.72 per Boe in the third quarter of 2019. The lower depletion rate per Boe was primarily driven by the decrease in our depletable base as a result of the impairment of oil and natural gas properties as well as lower reserve volumes due to reduced commodity pricing. Depreciation, amortization and accretion was $0.4 million and $0.3 million in the third quarter of 2020 and 2019, respectively. The following table summarizes DD&A expense per Boe for the third quarter of 2020 and 2019:

	Three Months Ended September 30,			
	2020	**2019**	**$ Change**	**% Change**
Depletion	$ 11.38	$ 14.72	$ (3.34)	(23) %
Depreciation, Amortization and Accretion	0.14	0.09	0.05	56 %
Total DD&A Expense	$ 11.52	$ 14.81	$ (3.29)	(22) %

Impairment of Oil and Natural Gas Properties

As a result of low commodity prices and their effect on the proved reserve values of our properties, we recorded a non-cash ceiling test impairment of $199.5 million in the third quarter of 2020. We did not record any impairment of our proved oil and gas properties in 2019. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at current levels, the trailing twelve-month average price used in the ceiling calculation will decline and will likely cause additional future write downs of our oil and natural gas properties. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing twelve-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $14.6 million in the third quarter of 2020 compared to $21.5 million in the third quarter of 2019. The decrease in interest expense was primarily due to lower interest rates on the debt outstanding and reduced principal amounts outstanding of our Second Lien Notes in the third quarter of 2020 compared to the third quarter of 2019.

Gain on Extinguishment of Debt

As a result of the Second Lien Notes exchanges during the third quarter of 2020 (see Note 4 to our condensed financial statements), we recorded a gain on extinguishment of debt of $1.6 million for the three months ended September 30, 2020 based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof. We did not record any gain or loss on extinguishment of debt during the third quarter of 2019.

Contingent Consideration Gain (Loss)

During the third quarter of 2020, we did not record a contingent consideration gain (loss), compared to a loss of $5.3 million in the third quarter of 2019 due to a change in the fair value of these liabilities. As of September 30, 2020, we had no contingent consideration liabilities remaining.

Income Tax

During the third quarters of 2020 and 2019, no income tax expense (benefit) was recorded on the income (loss) before income taxes, due to the valuation allowance placed on our net deferred tax asset because of the uncertainty regarding its realization. For further discussion of our valuation allowance, see Note 9 to our condensed financial statements.

We intend to continue to maintain a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of this allowance. However, sufficient positive evidence may become available to allow us to reach a conclusion that a portion of the valuation allowance will no longer be needed. Release of any portion of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded.

Results of Operations for the Nine Months Ended September 30, 2020 and September 30, 2019

The following table sets forth selected operating data for the periods indicated.

	Nine Months Ended September 30,		
	2020	2019	% Change
Net Production:			
Oil (Bbl)	6,852,520	8,106,534	(15) %
Natural Gas and NGLs (Mcf)	11,797,391	11,648,580	1 %
Total (Boe)	8,818,752	10,047,964	(12) %
Net Sales (in thousands):			
Oil Sales	$ 215,712	$ 416,259	(48) %
Natural Gas and NGL Sales	8,829	24,260	(64) %
Gain on Settled Commodity Derivatives	152,782	35,666	
Gain (Loss) on Unsettled Commodity Derivatives	124,800	(62,806)	
Other Revenue	13	10	
Total Revenues	502,136	413,389	21 %
Average Sales Prices:			
Oil (per Bbl)	$ 31.48	$ 51.35	(39) %
Effect of Gain on Settled Oil Derivatives on Average Price (per Bbl)	22.11	4.40	
Oil Net of Settled Oil Derivatives (per Bbl)	53.59	55.75	(4) %
Natural Gas and NGLs (per Mcf)	0.75	2.08	(64) %
Effect of Gain on Settled Natural Gas Derivatives on Average Price (per Mcf)	0.11	—	
Natural Gas and NGLs Net of Settled Natural Gas Derivatives (per Mcf)	0.86	2.08	(59) %
Realized Price on a Boe Basis Excluding Settled Commodity Derivatives	25.46	43.84	(42) %
Effect of Gain on Settled Commodity Derivatives on Average Price (per Boe)	17.33	3.55	
Realized Price on a Boe Basis Including All Realized Derivative Settlements	42.79	47.39	(10) %
Operating Expenses (in thousands):			
Production Expenses	$ 88,132	$ 83,146	6 %
Production Taxes	20,750	41,944	(51) %
General and Administrative Expenses	14,185	15,506	(9) %
Depletion, Depreciation, Amortization and Accretion	129,350	146,791	(12) %
Costs and Expenses (per Boe):			
Production Expenses	$ 9.99	$ 8.27	21 %
Production Taxes	2.35	4.17	(44) %
General and Administrative Expenses	1.61	1.54	5 %
Depletion, Depreciation, Amortization and Accretion	14.67	14.61	— %
Net Producing Wells at Period End	468.8	444.0	6 %

Oil and Natural Gas Sales

In the first nine months of 2020, our oil, natural gas and NGL sales, excluding the effect of settled commodity derivatives, decreased 49% as compared to the first nine months of 2019, driven by a 42% decrease in realized prices, excluding the effect of settled commodity derivatives, and a 12% decrease in production. The lower average realized price in the first nine months of 2020 as compared to the same period in 2019 was driven by lower average NYMEX oil prices and a higher oil price differential. Oil price differential during the first nine months of 2020 was $6.64 per barrel, as compared to $5.70 per barrel in the first nine months of 2019. The lower average realized price in the first nine months of 2020 as compared to the same period in 2019 was also driven by a 64% decrease in realized natural gas and NGL prices, excluding the effect of settled commodity derivatives, in the first nine months of 2020 compared to the same period of 2019. See “Market Conditions” above.

Curtailments, shut-ins and completion delays due to the significant decline in commodity prices drove a 12% decrease in production levels in the first nine months of 2020 compared to the same period in 2019. See “Impacts of COVID-19 Pandemic and Current Economic Environment” above.

Commodity Derivative Instruments

We enter into commodity derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on commodity derivatives, net, was a gain of $277.6 million in the first nine months of 2020, compared to a loss of $27.1 million in the first nine months of 2019. 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 2020, we realized a gain on settled commodity derivatives of $152.8 million, compared to a $35.7 million gain in the first nine months of 2019. The increase in the gain on settled derivatives was primarily due to a decrease in the average NYMEX oil price in the first nine months of quarter of 2020 compared to the same period of 2019. During the first nine months of 2020, our derivative settlements included 7.4 million barrels of oil at an average settlement price of $58.04 per barrel. During the first nine months of 2019, our commodity derivative settlements included 6.1 million barrels of oil at an average settlement price of $62.53 per barrel. The average NYMEX oil price for the first nine months of 2020 was $38.12 compared to $57.08 for the first nine months of 2019.

Unsettled commodity derivative gains and losses was a gain of $124.8 million in the first nine months of 2020, compared to a loss of $62.8 million in the first nine months of 2019. 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, 2020, all of our derivative contracts are recorded at their fair value, which was a net asset of $118.4 million, an increase of $123.6 million from the $5.2 million net liability recorded as of December 31, 2019. The increase in the net asset at September 30, 2020 as compared to December 31, 2019 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2019.

Production Expenses

Production expenses were $88.1 million in the first nine months of 2020, compared to $83.1 million in the first nine months of 2019. On a per unit basis, production expenses increased from $8.27 per Boe in the first nine months of 2019 to $9.99 per Boe in the first nine months of 2020. On an absolute dollar basis, the increase in our production expenses in the first nine months of 2020, as compared to the first nine months of 2019, was primarily due to a 6% increase in the total number of net producing wells, partially offset by a 12% decrease in production. The increase in production expenses on a per unit basis was due in part to production curtailments and shut-ins that negatively impacted our production in the first nine months of 2020.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $20.7 million in the first nine months of 2020 compared to $41.9 million in the first nine months of 2019. The decrease is due to lower realized prices and lower production, which decreased our oil and natural gas sales in the first nine months of 2020 as compared to the first nine months of 2019. As a percentage of oil and natural gas sales, our production taxes were 9.2% and 9.5% in the first nine months of 2020 and 2019, respectively.

General and Administrative Expenses

General and administrative expenses were $14.2 million in the first nine months of 2020 compared to $15.5 million in the first nine months of 2019. The decrease was primarily due to a $1.2 million decrease in professional fees and a $0.6 million decrease in compensation expense, primarily due to the timing of our performance-based equity awards, which was partially offset by a $0.4 million increase in insurance expense and other expenditures in the first nine months of 2020 compared to the first nine months of 2019.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $129.4 million in the first nine months of 2020, compared to $146.8 million in the first nine months of 2019. Depletion expense, the largest component of DD&A, decreased by $17.8 million in the first nine months of 2020 compared to the first nine months of 2019. The aggregate decrease in depletion expense was driven by a 12% decrease in production levels. On a per unit basis, depletion expense was $14.54 per Boe in the first nine months of 2020 compared to $14.53 per Boe in the first nine months of 2019. Depreciation, amortization and accretion was $1.1 million and $0.8 million in the first nine months of 2020 and 2019, respectively. The following table summarizes DD&A expense per Boe for the first nine months of 2020 and 2019:

	Nine Months Ended September 30,			
	2020	2019	$ Change	% Change
Depletion	$ 14.54	$ 14.53	$ 0.01	— %
Depreciation, Amortization and Accretion	0.12	0.08	0.04	50 %
Total DD&A Expense	$ 14.66	$ 14.61	$ 0.05	— %

Impairment of Oil and Natural Gas Properties

As a result of low commodity prices and their effect on the proved reserve values of our properties, we recorded a non-cash ceiling test impairment of $962.2 million in the first nine months of 2020. We did not record any impairment of our proved oil and gas properties in 2019. The impairment charge affected our reported net income but did not reduce our cash flow.

If commodity prices remain at current levels, the trailing twelve-month average price used in the ceiling calculation will decline and will likely cause additional future write downs of our oil and natural gas properties. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing twelve-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $45.1 million for the first nine months of 2020 compared to $58.8 million in the first nine months of 2019. The decrease in interest expense was primarily due to lower interest rates on the debt outstanding in the first nine months of 2020 compared to the first nine months of 2019. In addition, the series of Second Lien Notes exchanges completed in the fourth quarter of 2019 and in the first nine months of 2020 reduced our interest expense (See Note 4 to our condensed financial statements).

Loss on Extinguishment of Debt

As a result of the Second Lien Notes repurchases and exchanges during the first nine months of 2020 (see Note 4 to our condensed financial statements), we recorded a loss on extinguishment of debt of $3.7 million for the nine months ended September 30, 2020 based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof. During the first nine months of 2019, we recorded a loss on extinguishment of debt of $0.4 million.

Debt Exchange Derivative Gain (Loss)

For the first nine months of 2020, we did not record a debt exchange derivative gain (loss), compared to a gain of $1.4 million in the first nine months of 2019. As of September 30, 2020, we had no debt exchange derivative liabilities remaining.

Contingent Consideration Gain (Loss)

During the first nine months of 2020, we did not record a contingent consideration gain (loss), compared to a loss of $28.6 million in the first nine months of 2019 due to a change in the fair value of these liabilities. As of September 30, 2020, we had no contingent consideration liabilities remaining.

Income Tax

During the first nine months of 2020 and 2019, no income tax expense (benefit) was recorded on the income (loss) before income taxes, due to the valuation allowance placed on our net deferred tax asset because of the uncertainty regarding its realization. For further discussion of our valuation allowance, see Note 9 to our condensed financial statements.

We intend to continue to maintain a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of this allowance. However, sufficient positive evidence may become available to allow us to reach a conclusion that a portion of the valuation allowance will no longer be needed. Release of any portion of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded.

Non-GAAP Financial Measures

We define Adjusted Net Income (Loss) as net income (loss) excluding (i) (gain) loss on unsettled commodity derivatives, net of tax, (ii) (gain) loss on extinguishment of debt, net of tax, (iii) debt exchange derivative (gain) loss, net of tax, (iv) contingent consideration loss, net of tax, (v) acquisition transaction costs, net of tax, (vi) impairment of other current assets, net of tax, (vii) impairment expense, net of tax, (viii) (gain) loss on unsettled interest rate derivatives, net of tax, and (ix) write-off of debt issuance costs, net of tax. Our Adjusted Net Income for the third quarter of 2020 was $27.5 million or $0.51 per diluted share, compared to $36.3 million or $0.92 per diluted share for the third quarter of 2019. Our Adjusted Net Income for the first nine months of 2020 was $60.4 million or $1.17 per diluted share, compared to $99.4 million or $2.60 per diluted share for the first nine months of 2019. In both periods, the decrease in Adjusted Net Income is primarily due to lower realized commodity prices (after the effect of settled commodity derivatives), lower production levels and increased per unit production expenses.

We define Adjusted EBITDA as net income (loss) before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization and accretion, (iv) non-cash stock-based compensation expense, (v) (gain) loss on extinguishment of debt, (vi) debt exchange derivative (gain) loss, (vii) contingent consideration loss, (viii) (gain) loss on unsettled commodity derivatives, (ix) (gain) loss on unsettled interest rate derivatives, (x) impairment of other current assets, (xi) impairment expense, and (xii) write-off of debt issuance costs. Adjusted EBITDA for the third quarter of 2020 was $82.7 million, compared to Adjusted EBITDA of $124.4 million for the third quarter of 2019. Adjusted EBITDA for the first nine months of 2020 was $257.5 million, compared to Adjusted EBITDA of $340.0 million for the first nine months of 2019. In both periods, the decrease in Adjusted EBITDA is primarily due to lower realized commodity prices (after the effect of settled commodity derivatives), lower production levels and increased per unit production expenses.

Management believes the use of these non-GAAP financial measures provide useful information to investors to gain an overall understanding of our current financial performance. Specifically, management believes the non-GAAP financial measures included herein provide useful information to both management and investors by excluding certain items that our management believes are not indicative of our core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring our performance, and we believe that we are providing investors with financial measures that most closely align to our internal measurement processes. We consider these non-GAAP measures to be useful in evaluating our core operating results as they provide useful information regarding our essential revenue generating activities and direct operating expenses (resulting in cash expenditures) needed to perform these revenue generating activities. Our management also believes, based on feedback provided by the investment community, that the non-GAAP financial measures are necessary to allow the investment community to construct its valuation models to better compare our results with our competitors and market sector.

These measures should be considered in addition to our results of operations prepared in accordance with GAAP. In addition, these non-GAAP financial measures are not based on any comprehensive set of accounting rules or principles. We believe that non-GAAP financial measures have limitations in that they do not reflect all of the amounts associated with our results of operations as determined in accordance with GAAP and that these measures should only be used to evaluate our results of operations in conjunction with the corresponding GAAP financial measures.

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

Reconciliation of Adjusted Net Income

(In thousands, except share and per share data)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Net Income (Loss)	$ (233,004)	$ 94,381	$ (763,918)	$ 31,619
Add:				
Impact of Selected Items:				
(Gain) Loss on Unsettled Commodity Derivatives	70,198	(57,506)	(124,800)	62,806
Impairment of Other Current Assets	—	5,275	—	7,969
Write-off of Debt Issuance Costs	1,543	—	1,543	—
(Gain) Loss on Extinguishment of Debt	(1,592)	—	3,718	425
Debt Exchange Derivative (Gain) Loss	—	23	—	(1,390)
Contingent Consideration Loss	—	5,262	—	28,633
Acquisition Transaction Costs	—	1,250	—	1,763
(Gain) Loss on Unsettled Interest Rate Derivatives	(224)	—	1,205	—
Impairment Expense	199,489	—	962,205	—
Selected Items, Before Income Taxes	269,414	(45,696)	843,871	100,204
Income Tax of Selected Items[1]	(8,920)	(12,380)	(19,588)	(32,401)
Selected Items, Net of Income Taxes	260,494	(58,077)	824,283	67,803
Adjusted Net Income	$ 27,490	$ 36,304	$ 60,365	$ 99,422
Weighted Average Shares Outstanding – Basic	43,517,074	39,604,482	41,812,553	38,204,403
Weighted Average Shares Outstanding – Diluted	53,582,333	39,653,070	51,707,412	38,274,426
Net Income (Loss) Per Common Share – Basic	$ (5.35)	$ 2.38	$ (18.27)	$ 0.83
Add:				
Impact of Selected Items, Net of Income Taxes	5.98	(1.46)	19.71	1.77
Adjusted Net Income Per Common Share – Basic	$ 0.63	$ 0.92	$ 1.44	$ 2.60
Net Income (Loss) Per Common Share – Diluted	$ (4.35)	$ 2.38	$ (14.77)	$ 0.83
Add:				
Impact of Selected Items, Net of Income Taxes	4.86	(1.46)	15.94	1.77
Adjusted Net Income Per Common Share – Diluted	$ 0.51	$ 0.92	$ 1.17	$ 2.60

(1) For the three and nine months ended September 30, 2020, this represents a tax impact using an estimated tax rate of 24.5%, which includes an adjustment of $57.1 million and $187.2 million, respectively, for a change in valuation allowance. For the three and nine months ended September 30, 2019, this represents a tax impact using an estimated tax rate of 24.5%, which includes an adjustment of $23.6 million and $7.9 million, respectively, for a change in valuation allowance.

Reconciliation of Adjusted EBITDA

(In thousands)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Net Income (Loss)	$ (233,004)	$ 94,381	$ (763,918)	$ 31,619
Add:				
Interest Expense	14,637	21,510	45,145	58,836
Income Tax Provision (Benefit)	—	—	(166)	—
Depreciation, Depletion, Amortization and Accretion	30,786	55,566	129,350	146,791
Impairment of Other Current Assets	—	5,275	—	7,969
Non-Cash Stock-Based Compensation	890	(114)	3,183	4,280
Write-off of Debt Issuance Costs	1,543	—	1,543	—
(Gain) Loss on Extinguishment of Debt	(1,592)	—	3,718	425
Debt Exchange Derivative (Gain) Loss	—	23	—	(1,390)
Contingent Consideration Loss	—	5,262	—	28,633
(Gain) Loss on Unsettled Interest Rate Derivatives	(224)	—	1,205	—
(Gain) Loss on Unsettled Commodity Derivatives	70,198	(57,506)	(124,800)	62,806
Impairment Expense	199,489	—	962,205	—
Adjusted EBITDA	$ 82,723	$ 124,396	$ 257,465	$ 339,968

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, credit facility borrowings, and cash settlements of commodity derivative instruments. Our primary uses of capital have been for the acquisition and development of our oil and natural gas properties. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

In the first quarter of 2020, we strengthened our balance sheet via several separate agreements whereby, in the aggregate, we repurchased and retired $76.7 million in principal amount of our 8.500% senior secured second lien notes due 2023 (the "Second Lien Notes") in exchange for aggregate consideration consisting of $2.5 million in cash and newly-issued shares of our 6.500% Series A Perpetual Cumulative Convertible Preferred Stock (the "Series A Preferred Stock") having an aggregate liquidation preference of $79.5 million. In the second and third quarters of 2020, we further strengthened our balance sheet via several separate exchange agreements whereby, in the aggregate: (i) we retired an additional $39.7 million of Second Lien Notes in exchange for 4.2 million shares of our common stock, and (ii) we retired Series A Preferred Stock having an aggregate liquidation preference of $7.6 million in exchange for 0.5 million shares of our common stock.

As of September 30, 2020, we had outstanding debt consisting of $571.0 million of borrowings under our Revolving Credit Facility, $287.8 million aggregate principal amount of Second Lien Notes and $130.0 million aggregate principal amount under the Unsecured VEN Bakken Note. We had total liquidity of $90.8 million as of September 30, 2020, consisting of $89.0 million of borrowing availability under the Revolving Credit Facility and $1.8 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 77% and 80% of our total production volumes in the third quarter of 2020 and 2019, 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 the price of crude oil with respect to a portion of our expected oil production. In 2019, we hedged approximately 76% of our crude oil production. For the three months ended September 30, 2020, due to the significant reduction in our production as a result of the precipitous decline in commodity prices, we hedged approximately 104% of our crude oil production. For a summary as of September 30, 2020, of our open commodity swap contracts for future periods, see "Quantitative and Qualitative Disclosures about Market Risk" in Part I, Item 3 below.

See "Impacts of COVID-19 Pandemic and Current Economic Environment" above for additional information regarding our liquidity and capital resources in the current environment.

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, 2020, we had a working capital surplus of $13.3 million, compared to a deficit of $70.4 million at December 31, 2019. Current assets increased by $50.7 million and current liabilities decreased by $33.0 million at September 30, 2020, compared to December 31, 2019. The increase in current assets is primarily due to an increase in our derivative instruments of $113.8 million due to the change in fair value as a result of the commodity price environment, which was partially offset by a $48.2 million reduction in our accounts receivable due to lower commodity prices and shut-in and curtailed production volumes. The change in current liabilities is due to an $89.2 million decrease in our accounts payable and accrued liabilities due in part to reduced activity levels in the Williston Basin and a $5.9 million decrease in our derivative instruments, partially offset by an increase in the current portion of our long-term debt of $65.0 million related to our Unsecured VEN Bakken Note.

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. The Company typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and gas production for the next 12 to 24 months. As of September 30, 2020, we had entered into commodity derivative swap contracts hedging 2.4 million barrels of oil for the remainder of 2020 at an average price of $58.03 per barrel, 7.8 million barrels of oil in 2021 at an average price of $54.67 per barrel and 0.4 million barrels of oil in 2022 at an average weighted price of $50.05. In addition, we had entered into natural gas derivative swap contracts hedging 2.8 million MMbtu for the remainder of 2020 at an average price of $2.44 per MMbtu, 13.0 million MMbtu in 2021 at an average price of $2.50 per MMbtu, and 1.8 million MMbtu in 2022 at an average price of $2.53 per MMbtu.

Our cash flows for the nine months ended September 30, 2020 and 2019 are presented below:

	Nine Months Ended September 30,	
	2020	**2019**
	(in thousands, unaudited)	
Net Cash Provided by Operating Activities	$ 258,652	$ 269,323
Net Cash Used for Investing Activities	(249,552)	(417,948)
Net Cash Provided by (Used for) Financing Activities	(23,365)	148,169
Net Change in Cash	$ (14,265)	$ (456)

Cash Flows from Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2020 was $258.7 million, compared to $269.3 million in the same period of the prior year. This decrease was due to lower realized prices (including the effect of settled derivatives) and lower production volumes which was partially offset by changes in working capital and lower interest 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, 2020 was an increase of $42.9 million compared to a decrease of $15.3 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, 2020 and 2019 were $249.6 million and $417.9 million, respectively. The decrease in cash used in investing activities for the first nine months of 2020 as compared to the same period of 2019 was attributable to a $167.7 million decrease in our development and acquisition spending. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $76.5 million and $178.8 million at September 30, 2020 and 2019, 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, 2020, our capitalized costs incurred for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $165.0 million, while the actual cash spend in this regard amounted to $249.3 million because we settled accrued capital expenditure liabilities incurred in 2019 during 2020.

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, 2020 and 2019 are summarized in the following table:

	Nine Months Ended September 30,	
	2020	2019
	(in millions, unaudited)	
Drilling and Development Capital Expenditures	$ 217.2	$ 205.4
Acquisition of Oil and Natural Gas Properties	31.1	210.6
Other Capital Expenditures	1.0	0.9
Total	$ 249.3	$ 416.9

Cash Flows from Financing Activities

Net cash used for financing activities was $23.4 million during the nine months ended September 30, 2020, compared to net cash provided by financing activities of $148.2 million during the nine months ended September 30, 2019. For the nine months ended September 30, 2020, cash used for financing activities was primarily related to $13.5 million in repurchases of Second Lien Notes and $9.0 million of net repayments under our Revolving Credit Facility. For the nine months ended September 30, 2019, cash provided by financing activities was primarily related to $187.0 million of net borrowings under our Revolving Credit Facility which was partially offset by $15.1 million in repurchases of common stock, $10.5 million in repurchases of Second Lien Notes and $12.3 million for settlements related to our contingent consideration and debt exchange derivative liabilities.

Revolving Credit Facility

In November 2019, we entered into a revolving credit facility with Wells Fargo Bank, as administrative agent, and the lenders from time to time party thereto (the “Revolving Credit Facility”), which amended and restated our existing revolving credit facility that was entered into on October 5, 2018. 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, 2020, the Revolving Credit Facility had a borrowing base of $660.0 million and we had $571.0 million in borrowings outstanding under the facility, leaving $89.0 million in available borrowing capacity. See Note 4 to our condensed financial statements for further details regarding the Revolving Credit Facility.

Second Lien Notes due 2023

As of September 30, 2020, we had $287.8 million in outstanding principal amount of our 8.500% senior secured second lien notes due 2023. See Note 4 to our condensed financial statements for further details regarding the Second Lien Notes.

Unsecured VEN Bakken Note

As of September 30, 2020, we had $130.0 million in outstanding principal amount under the Unsecured VEN Bakken Note. See Note 4 to our condensed financial statements for further details regarding the Unsecured VEN Bakken Note.

Series A Preferred Stock

As of September 30, 2020, we had 2,218,732 outstanding shares of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock (the “Series A Preferred Stock”), having an aggregate liquidation preference of $221.9 million. See Note 5 to our condensed financial statements for further details regarding the Series A Preferred Stock.

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. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Contractual Obligations and Commitments

Please see our disclosure of contractual obligations and commitments as of December 31, 2019, included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

Significant Accounting Policies

Our critical accounting policies involving significant estimates include impairment testing of natural gas and crude oil production properties, asset retirement obligations, revenue recognition, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting policies involving significant estimates from those reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

A description of our critical accounting policies 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, 2019.

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, 2019 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 oil 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 swap contracts as of September 30, 2020, by fiscal quarter.

Contract Period	Oil (Barrels)		Weighted Average Price ($)
Swaps-Crude Oil			
2020:			
Q4	2,372,362		58.03
2021[(1)]:			
Q1	2,201,250	$	55.53
Q2	1,997,458		55.88
Q3	1,809,410		53.46
Q4	1,800,506		53.47
2022[(2)]:			
Q1	90,000	$	50.05
Q2	91,000		50.05
Q3	92,000		50.05
Q4	92,000		50.05

(1) We have entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for additional periods. Options covering a notional volume of 0.3 million barrels for 2021 are exercisable on or about December 31, 2020. If the counterparties exercise all such options, the notional volume of our existing crude oil derivative contracts will increase as follows for 2021: (i) for the first quarter of 2021, by 112,500 barrels at a weighted average price of $57.78 per barrel, (ii) for the second quarter of 2021, by 113,750 barrels at a weighted average price of $57.78 per barrel, (iii) for the third quarter of 2021, by 46,000 barrels at a weighted average price of $58.00 per barrel, and (iv) for the fourth quarter of 2021, by 46,000 barrels at a weighted average price of $58.00 per barrel.

(2) We have entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for additional periods. Options covering a notional volume of 3.1 million barrels for 2022 are exercisable on or about December 31, 2021. If the counterparties exercise all such options, the notional volume of our existing crude oil derivative contracts will increase as follows for 2022: (i) for the first quarter of 2022, by 1,010,250 barrels at a weighted average price of $53.20 per barrel, (ii) for the second quarter of 2022, by 1,021,475 barrels at a weighted average price of $53.20 per barrel, (iii) for the third quarter of 2022, by 549,700 barrels at a weighted average price of $51.71 per barrel, and (iv) for the fourth quarter of 2022, by 549,700 barrels at a weighted average price of $51.71 per barrel. Additionally, counterparties have options covering a notional volume of 1.1 million for 2023 at a weighted average price of $46.59 per barrel.

The following table summarizes our open natural gas swap contracts as of September 30, 2020, by fiscal quarter.

Contract Period	Gas (MMBTU)	Weighted Average Price ($)
Swaps-Natural Gas		
2020:		
Q4	2,760,000	$ 2.44
2021:		
Q1	3,375,000	$ 2.47
Q2	3,185,000	2.51
Q3	3,220,000	2.51
Q4	3,220,000	2.51
2022:		
Q1	450,000	$ 2.53
Q2	455,000	2.53
Q3	460,000	2.53
Q4	460,000	2.53

Interest Rate Risk

Our long-term debt as of September 30, 2020 is comprised of borrowings that contain fixed and floating interest rates. The Second Lien Notes and our Unsecured VEN Bakken Note 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. At our option, borrowings under the Revolving Credit Facility bear interest at the base rate or LIBOR, plus an applicable margin. The base rate is 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 LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 100 to 200 basis points, and the applicable margin for LIBOR loans ranges from 200 to 300 basis points, in each case depending on the percentage of the borrowing base utilized. Interest payments are due under the Revolving Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Revolving Credit Facility.

The Company uses interest rate swaps to effectively convert a portion of its variable rate indebtedness to fixed rate indebtedness. As of September 30, 2020, we had interest rate swaps with a total notional amount of $200.0 million.

As a result, 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, 2020 would cost us approximately $3.7 million in additional annual interest expense.

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 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, 2020, 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, 2020.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended September 30, 2020, that materially affected or are 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 below, 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, 2019.

The global COVID-19 pandemic and recent oil market developments have negatively impacted and will likely continue to impact us, and could have a material adverse effect on our business, financial condition, liquidity, results of operations and prospects.

Since the beginning of 2020, the COVID-19 pandemic has spread across the globe and disrupted economies around the world, including the oil and gas industry in which we operate. The rapid spread of the coronavirus has led to the implementation of various responses, including federal, state and local government-imposed quarantines, shelter-in-place mandates, sweeping restrictions on travel, and other public health and safety measures, nearly all of which have materially reduced global demand for crude oil. The extent to which the global COVID-19 pandemic impacts will continue to affect our business, financial condition, liquidity, results of operations, prospects, and the demand for our production will depend on future developments, which are highly uncertain and cannot be predicted with confidence, including the duration or any recurrence of the outbreak and responsive measures, additional or modified government actions, new information which may emerge concerning the severity of the global COVID-19 pandemic and the effectiveness of actions taken to contain the coronavirus or treat its impact now or in the future, among others.

In addition, disputes in the first quarter of 2020 between OPEC and Russia resulted in Saudi Arabia significantly discounting the price of its crude oil, as well as Saudi Arabia and Russia significantly increasing their oil supply, leading to a substantial decline in oil prices. While OPEC, Russia and other allied producers reached an agreement in April 2020 to reduce production, oil prices have remained very low. Many operators in the Williston Basin have responded by significantly decreasing drilling and completion activity, and by shutting in or curtailing production from a significant number of producing wells.

The foregoing has had, and we expect will continue to have, an adverse effect on our business, financial condition, liquidity and results of operations. These factors will likely have the effect of heightening many of the risks described in the “Risk Factors” section of our Annual Report on Form 10-K for the year ended December 31, 2019, such as those relating to our indebtedness, our access to capital, our liquidity, potential reductions in the borrowing base under our revolving credit facility, our need to generate sufficient cash flows to service our indebtedness, and our ability to comply with the covenants contained in the agreements that govern our indebtedness.

Without limiting the generality of the foregoing, some impacts of the COVID-19 pandemic and recent oil market developments that could have an adverse effect on our business, financial condition, liquidity and results of operations, include:

- significantly reduced prices for our oil production, resulting from a world-wide decrease in demand for hydrocarbons and a resulting oversupply of existing production;
- further decreases in the demand for our oil production, resulting from significantly decreased levels of global, regional and local travel as a result of federal, state and local government-imposed quarantines, including shelter-in-place mandates, enacted to slow the spread of the coronavirus;
- significantly reduced development activity on our properties by operators in the Willison Basin;
- increased likelihood that the operators of our wells will curtail or shut-in production, either voluntarily or as a result of third-party and regulatory mandates, due to depressed oil prices, lack of storage, and/or other market, social, legal, or political forces;
- increased costs associated with, or actual unavailability of, facilities for the storage of oil, gas and NGL production, in the markets in which we operate;
- increased operational difficulties associated with, or an inability to, deliver oil and NGLs to end-markets, resulting from pipeline and storage constraints;

- the potential for loss of leasehold or asset value for failure to produce oil and gas in paying quantities;
- increased third-party credit risk resulting from adverse market conditions, a lack of access to capital and storage, and the failure of certain of our counterparties to continue as going concerns;
- increased costs, either directly or indirectly, related to facility modifications, social distancing measures or other best practices implemented in response to the COVID-19 pandemic and or due to changes in federal, state, and local laws and regulations;
- increased shareholder activism;
- reducing estimated volumes and value attributable to our proved reserves;
- reducing the carrying value of our oil and gas properties due to recognizing impairments on such properties; and
- limiting access to, or increasing the cost of, sources of capital such as equity and long-term debt.

In addition, the COVID-19 pandemic and recent oil market developments may also affect our business, operations or financial condition in a manner that is not presently known to us or that we currently do not expect to present a significant risk to our business, operations or financial condition.

Our business depends on oil and natural gas transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, physical damage, scheduled maintenance, legal or other reasons such as suspension of service due to legal challenges (see below regarding the Dakota Access Pipeline), could result in a substantial increase in costs, the shut-in of producing wells or the delay or discontinuance of development plans for our properties. During 2019, we experienced significant delays and production curtailments that we believe were due in part to gas gathering and processing constraints. The negative effects arising from these and similar circumstances may last for an extended period of time. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, many of our wells are drilled in locations in the Williston Basin that are serviced to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third party oil trucking to transport a significant portion of our production to third party transportation pipelines, rail loading facilities and other market access points.

The Dakota Access Pipeline (“DAPL”), a major pipeline running out of the Williston Basin, is subject to highly publicized ongoing litigation (the “DAPL Litigation”) that could threaten its continued operation. In July 2020, a federal district court ordered DAPL to be shut down no later than August 6, 2020, pending the completion of an environmental impact statement (“EIS”) that is expected to take at least a year to complete. The district court’s shut-down order was subsequently temporarily stayed by a federal circuit court of appeals, and DAPL currently remains operational. But a court-ordered shut-down remains possible, and there is no guarantee that DAPL will be permitted to resume or continue operations following the completion of the EIS and/or the DAPL Litigation.

Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

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

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, 2020.

Period	Total Number of Shares Purchased[1]	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[2]
Month #1				
July 1, 2020 to July 31, 2020	—	—	—	$ 68.1 million
Month #2				
August 1, 2020 to August 31, 2020	—	—	—	68.1 million
Month #3				
September 1, 2020 to September 30, 2020	—	—	—	68.1 million
Total	—	—	—	$ 68.1 million

(1) No shares were surrendered in satisfaction of tax withholding obligations in connection with the vesting of restricted stock awards during these periods.

(2) In May 2011, our board of directors approved 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 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	By-Laws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 15, 2018
3.4	Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated November 22, 2019	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 26, 2019
3.5	Certificate of Amendment to the Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated January 2, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 6, 2020
3.6	Certificate of Amendment to the Certificate of Designations of 6.500% Series A Perpetual Cumulative Convertible Preferred Stock of Northern Oil and Gas, Inc., dated January 17, 2020	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 22, 2020
4.1	Indenture, dated May 15, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.50% Senior Secured Second Lien Notes due 2023)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
4.2	First Supplemental Indenture, dated September 18, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018
4.3	Second Supplemental Indenture, dated October 5, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018
4.4	Third Supplemental Indenture, dated November 22, 2019, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 26, 2019
10.1	First Amendment to the Second Amended and Restated Credit Agreement, dated July 8, 2020, by and among Northern Oil and Gas, Inc. and Wells Fargo Bank, National Association and the Lenders party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 13, 2020
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, 2020, formatted in Inline XBRL and contained in Exhibit 101	Filed herewith

SIGNATURES

In accordance with the requirements of the Exchange Act, the Registrant has caused this Quarterly Report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date:	November 6, 2020	By:	/s/ Nicholas O'Grady
			Nicholas O'Grady, Chief Executive Officer and principal executive officer (on behalf of Registrant)
Date:	November 6, 2020	By:	/s/ Chad Allen
			Chad Allen, Chief Financial Officer and principal accounting officer

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 6, 2020

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 6, 2020

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, 2020, 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 6, 2020

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

Dated: November 6, 2020

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.