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

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2020
OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _______________ to _______________

Commission file number 001-31446

CIMAREX ENERGY CO.

(Exact name of registrant as specified in its charter)

Delaware	**45-0466694**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Lincoln Street, Suite 3700 Denver Colorado	**80203**
(Address of principal executive offices)	(Zip Code)

(303) 295-3995
(Registrant’s telephone number)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock ($0.01 par value)	XEC	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
			Emerging Growth Company ☐

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

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

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

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2020 was approximately $2.75 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of January 31, 2021 was 102,807,656.

Documents Incorporated by Reference: Portions of the Registrant’s Proxy Statement for its 2021 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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DESCRIPTION

GLOSSARY

Bbls—Barrels (of oil or natural gas liquids)

Bcf—Billion cubic feet (of natural gas)

BOE—Barrels of oil equivalent

GAAP—Generally accepted accounting principles in the U.S.

Gross Acres or Gross Wells—The total acres or wells in which a working interest is owned.

MBbls—Thousand barrels

MBOE—Thousand barrels of oil equivalent

Mcf—Thousand cubic feet

MMBbls—Million barrels

MMBtu—Million British thermal units

MMBOE—Million barrels of oil equivalent

MMcf—Million cubic feet

Net Acres or Net Wells—The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

Net Production—Gross production multiplied by net revenue interest

NGL or NGLs—Natural gas liquids

PUD—Proved undeveloped

Tcf—Trillion cubic feet

Energy equivalent is determined using the ratio of one barrel of crude oil, condensate, or NGL to six Mcf of natural gas.

PART I

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-K, we make statements that may be deemed “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. In particular, in our Management’s Discussion and Analysis of Financial Condition and Results of Operations, we provide projections of our 2021 capital expenditures. All statements, other than statements of historical facts, that address activities, events, outcomes, and other matters that Cimarex plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates, or anticipates (and other similar expressions) will, should, or may occur in the future are forward-looking statements. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K for the year ended December 31, 2020. All the risks disclosed in this Form 10-K may be amplified by the COVID-19 pandemic and its unpredictable nature. Forward-looking statements include statements with respect to, among other things:

- Fluctuations in the price we receive for our oil, gas, and NGL production, including local market price differentials, which may be exacerbated by the demand destruction resulting from the highly transmissible and pathogenic coronavirus known as severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) that causes the disease known as COVID-19;

- Disruptions to the availability of workers and contractors due to illness and stay-at-home orders related to the COVID-19 pandemic;

- Cost and availability of gathering, pipeline, refining, transportation and other midstream and downstream activities and our ability to sell oil, gas, and NGLs, which may be negatively impacted by the COVID-19 pandemic and other risks and lead to a lack of any available markets;

- Availability of supply chains and critical equipment and supplies, which may be negatively impacted by the COVID-19 pandemic and other risks;

- Higher than expected costs and expenses, including the availability and cost of services and materials, which may be negatively impacted by the COVID-19 pandemic;

- Compliance with environmental and other regulations, including new regulations that may result from the recent change in federal and state administrations and legislatures;

- Legislative or regulatory changes, including initiatives related to hydraulic fracturing, emissions, and disposal of produced water, which may be negatively impacted by the recent change in Presidential administration or legislatures;

- The ability to receive drilling and other permits or approvals and rights-of-way in a timely manner (or at all), which may be negatively impacted by the impact of COVID-19 restrictions on regulatory employees who process and approve permits, other approvals and rights-of-way and which may be restricted by new Presidential and Secretarial orders and regulation and legislation;

- Reductions in the quantity of oil, gas, and NGLs sold and prices received because of decreased demand and/or curtailments in production relating to mechanical, transportation, storage, capacity, marketing, weather, the COVID-19 pandemic, or other problems;

- Declines in the SEC PV10 value of our oil and gas properties resulting in full cost ceiling test impairments to the carrying values of our oil and gas properties;

- The effectiveness of our internal control over financial reporting;

- Success of the company’s risk management activities;
- Availability of financing and access to capital markets;
- Estimates of proved reserves, exploitation potential, or exploration prospect size;
- Greater than expected production decline rates;
- Timing and amount of future production of oil, gas, and NGLs;
- Cybersecurity threats, technology system failures, and data security issues;
- The inability to transport, process, and store oil and gas;
- Hedging activities and the viability of our hedging counterparties, many of whom have been negatively impacted by the COVID-19 pandemic;
- Economic and competitive conditions;
- Lack of available insurance;
- Cash flow and anticipated liquidity;
- Continuing compliance with the financial covenant contained in our amended and restated credit agreement;
- The loss of certain federal income tax deductions;
- Litigation;
- Environmental liabilities;
- New federal regulations regarding species or habitats;
- Exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties;
- Drilling of wells;
- Development drilling and testing results;
- Performance of acquired properties and newly drilled wells;
- Ability to obtain industry partners to jointly explore certain prospects, and the willingness and ability of those partners to meet capital obligations when requested;
- Unexpected future capital expenditures;
- Amount, nature, and timing of capital expenditures;
- Proving up undeveloped acreage and maintaining production on leases;
- Unforeseen liabilities associated with acquisitions and dispositions;
- Establishing valuation allowances against our net deferred tax assets;

- Potential payments for failing to meet minimum oil, gas, NGL, or water delivery or sales commitments;
- Increased financing costs due to a significant increase in interest rates;
- Risks associated with concentration of operations in one major geographic area;
- Availability and cost of capital;
- Title to properties;
- Ability to complete property sales or other transactions; and
- Other factors discussed in the company's reports filed with the Securities and Exchange Commission ("SEC").

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production, and sale of oil, gas, and NGLs.

These risks include, but are not limited to, commodity price volatility, demand, capacity, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and gas reserves and in projecting future rates of production, production type curves, well spacing, timing of development expenditures, and other risks described herein. Many of these risks can be exacerbated by epidemics and pandemics including the current COVID-19 pandemic.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data by our engineers. As a result, estimates made by different engineers often vary from one another. In addition, the results of drilling, testing, and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the timing of future production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately recovered.

Risk factors related to acquisitions, including our acquisition of Resolute Energy Corporation in 2019, include, among others: unknown liabilities related to the acquired properties or entities; the risk that problems may arise in successfully integrating the businesses of the companies, which may result in the combined company not operating as effectively and efficiently as expected; the risk that the combined company may be unable to achieve synergies or other anticipated benefits of the transaction; or it may take longer than expected to achieve those synergies or benefits, and other important factors, such as expenses related to integration, that could cause actual results to differ materially from those projected.

Should one or more of the risks or uncertainties described above or elsewhere in this Annual Report on Form 10-K for the year ended December 31, 2020 cause our underlying assumptions to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, express or implied, included in or incorporated by reference into this Form 10-K and attributable to Cimarex are qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Cimarex or persons acting on its behalf may issue. Cimarex does not undertake any obligation to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the SEC, except as required by law.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Cimarex Energy Co., a Delaware corporation formed in 2002, is an independent oil and gas exploration and production company. Our operations are located entirely within the United States of America, mainly in Texas, New Mexico, and Oklahoma. Currently our operations are focused in two main areas: the Permian Basin and the Mid-Continent. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. On our website — www.cimarex.com — you will find our annual reports, proxy statements, and all of our Securities and Exchange Commission ("SEC") filings, which we make available free of charge. Information contained on our website is not incorporated by reference into this Annual Report. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Our principal business objective is to increase shareholder value through the profitable growth of our proved reserves and production while seeking to minimize our impact on the communities in which we operate for the long-term. Our strategy centers on maximizing cash flow from producing properties for reinvestment in exploration and development activities and for providing cash returns to shareholders through dividends and debt reduction. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-strategic assets. Key elements to our approach include:

- Maintaining a strong financial position;
- Investing in a diversified portfolio of drilling opportunities;
- Evaluating projects based on rate-of-return and rank investment decisions;
- Tracking predicted versus actual results in a centralized exploration management system to provide feedback to improve results;
- Attracting quality employees and maintaining integrated teams of geoscientists, landmen, and engineers; and
- Maximizing profitability.

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage coupled with strong full-cycle returns enables us to better withstand volatility in commodity prices and provide competitive returns and growth to shareholders. See Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Stock Performance Graph and Item 6 Selected Financial Data for additional financial and operating information for fiscal years 2016 - 2020.

Proved Oil and Gas Reserves

Our December 31, 2020 total proved reserves decreased 14% from prior year-end. Proved undeveloped reserves as a percentage of total proved reserves increased to 16% from 14% a year ago. During 2020, we added 56.6 MMBOE of new reserves through extensions and discoveries and had net negative revisions that totaled 52.4 MMBOE. These revisions consisted primarily of 70.3 MMBOE in downward price revisions and 10.0 MMBOE associated with the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure, partially offset by 30.7 MMBOE in positive revisions related to decreases in operating expenses. The change in our proved reserves is as follows:

	Proved Reserves (MBOE)
Reserves at December 31, 2019	619,595
Revisions of previous estimates	(52,430)
Extensions and discoveries	56,575
Production	(92,412)
Sales of reserves	(307)
Reserves at December 31, 2020	531,021

A breakdown by commodity of our proved oil and gas reserves follows:

	December 31,		
	2020	2019	2018
Proved reserves:			
Gas (MMcf)	1,362,842	1,532,145	1,591,321
Oil (MBbls)	144,063	169,770	146,538
NGL (MBbls)	159,818	194,468	179,436
Total (MBOE)	531,021	619,595	591,195
Percent developed	84 %	86 %	85 %

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2020.

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)	% of Total Proved Reserves
Mid-Continent	570,578	17,491	56,130	168,717	32 %
Permian Basin	790,750	126,327	103,606	361,725	68 %
Other	1,514	245	82	579	— %
	1,362,842	144,063	159,818	531,021	100 %

See **SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)** in Item 8 for further information regarding our reserves.

Production Volumes, Prices, and Costs

All of our oil and gas assets are located in the United States of America. We have varying levels of ownership interests in our properties consisting of working, royalty, and overriding royalty interests. Operated wells account for approximately 87% of our proved reserves.

Our 2020 production volumes totaled 252.5 MBOE per day, a 9% decrease from 2019, and were comprised of 42% gas, 30% oil, and 28% NGLs. The following table presents our total and average daily production volumes by region.

	Total Production Volumes				Average Daily Production Volumes			
Years Ended December 31,	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Total (MBOE)**	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Total (MBOE)**
2020								
Permian Basin	148,227	24,810	17,831	67,345	405.0	67.8	48.7	184.0
Mid-Continent	84,016	3,219	7,700	24,922	229.6	8.8	21.0	68.1
Other	382	58	23	145	1.0	0.1	0.1	0.4
Total company	232,625	28,087	25,554	92,412	635.6	76.7	69.8	252.5
2019								
Permian Basin	145,612	26,376	18,973	69,618	398.9	72.3	52.0	190.8
Mid-Continent	105,515	5,033	9,263	31,882	289.1	13.8	25.4	87.3
Other	440	54	18	145	1.2	0.1	—	0.4
Total company	251,567	31,463	28,254	101,645	689.2	86.2	77.4	278.5
2018								
Permian Basin	92,593	19,104	11,499	46,035	253.7	52.3	31.5	126.1
Mid-Continent	112,697	5,530	10,474	34,787	308.8	15.2	28.7	95.3
Other	547	76	21	188	1.4	0.2	0.1	0.5
Total company	205,837	24,710	21,994	81,010	563.9	67.7	60.3	221.9

At December 31, 2020, we had three fields that contained 15% or more of our total proved reserves. These fields were Watonga-Chickasha in the Cana area of the Mid-Continent, Dixieland in the Permian Basin in Reeves County, Texas, and Ford West in the Permian Basin in Culberson County, Texas. At December 31, 2020, the Watonga-Chickasha, Dixieland, and Ford West fields contained approximately 29%, 22%, and 16%, respectively, of our total proved reserves. At December 31, 2019, these same three fields contained 15% or more of our total proved reserves. At December 31, 2018, we had two fields that contained 15% or more of our total proved reserves, the Watonga-Chickasha and Ford West fields. Production for these fields is presented in the following table.

	Total Production Volumes				Average Daily Production Volumes			
Years Ended December 31,	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Total (MBOE)**	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Total (MBOE)**
2020								
Watonga-Chickasha	70,434	2,917	7,201	21,858	192.4	8.0	19.7	59.7
Dixieland	45,463	8,478	5,397	21,453	124.2	23.2	14.7	58.6
Ford West	42,832	4,485	5,095	16,719	117.0	12.3	13.9	45.7
2019								
Watonga-Chickasha	90,148	4,643	8,689	28,357	247.0	12.7	23.8	77.7
Dixieland	42,658	8,938	5,934	21,982	116.9	24.5	16.3	60.2
Ford West	41,087	5,042	5,212	17,102	112.6	13.8	14.3	46.9
2018								
Watonga-Chickasha	96,043	5,072	9,809	30,889	263.1	13.9	26.9	84.6
Dixieland	11,940	2,902	1,538	6,430	32.7	7.9	4.2	17.6
Ford West	30,976	3,777	3,823	12,763	84.9	10.3	10.5	35.0

The following table presents the average commodity prices received and production cost per unit of production by region.

Years Ended December 31,	Average Realized Price Gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Production Cost (per BOE)
2020				
Permian Basin	$ 0.69	$ 35.66	$ 9.64	$ 3.14
Mid-Continent	$ 1.67	$ 34.97	$ 12.60	$ 2.92
Other	$ 1.98	$ 41.15	$ 9.42	$ 6.13
Total company	$ 1.05	$ 35.59	$ 10.53	$ 3.09
2019				
Permian Basin	$ 0.49	$ 52.55	$ 12.62	$ 3.47
Mid-Continent	$ 1.95	$ 53.89	$ 15.47	$ 3.04
Other	$ 2.44	$ 56.52	$ 15.70	$ 9.59
Total company	$ 1.11	$ 52.77	$ 13.55	$ 3.34
2018				
Permian Basin	$ 1.69	$ 54.95	$ 22.84	$ 4.37
Mid-Continent	$ 2.23	$ 62.31	$ 21.67	$ 2.69
Other	$ 2.97	$ 58.40	$ 26.46	$ 7.63
Total company	$ 1.99	$ 56.61	$ 22.28	$ 3.66

Acquisitions and Divestitures

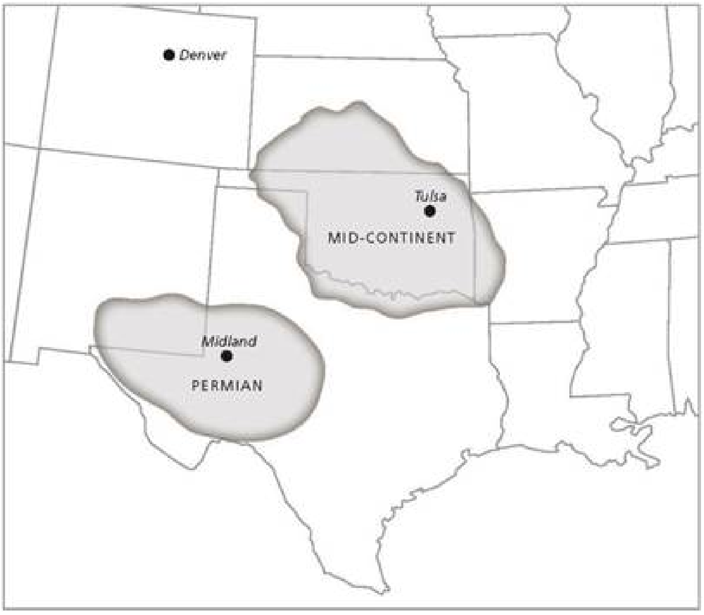
We consider property acquisitions, divestitures, and occasional mergers to enhance our competitive position. Moreover, sales of non-strategic assets are a source of liquidity that we can use to supplement funding of capital expenditures and acquisitions of strategic assets.

On September 30, 2020, we closed on the sale of certain water infrastructure assets in Eddy County, New Mexico, for which we received net cash proceeds of $68.7 million during 2020, as adjusted for customary closing adjustments and transaction costs. See Note 13 to the Consolidated Financial Statements for further information on this divestiture.

On March 1, 2019, we completed the acquisition of Resolute Energy Corporation ("Resolute"), an independent oil and gas company focused on the acquisition and development of unconventional oil and gas properties in the Delaware Basin area of the Permian Basin of west Texas. This acquisition expanded our footprint in Reeves County, Texas on acreage complementary to our existing Reeves County position. We paid $325.7 million in cash and issued common and preferred stock valued at an aggregate of $494.6 million, for total consideration transferred of $820.3 million. In addition, we assumed $870.0 million of Resolute's long-term debt, which we immediately repaid. See Note 13 to the Consolidated Financial Statements for further information on this acquisition.

Exploration and Development Overview

Cimarex has one reportable segment, exploration and production. Our exploration and production activities take place primarily in two areas: the Permian Basin and the Mid-Continent. Almost all of our exploration and development ("E&D") capital is allocated between these two areas.



A summary of our 2020 exploration and development activity and capital investments is as follows:

	Capital Investment	Gross Productive Wells Completed	Net Productive Wells Completed
	(in thousands)		
Exploration and development:			
Permian Basin	$ 503,304	92	48.1
Mid-Continent	40,825	57	2.9
Other	727	—	—
	544,856	149	51.0
Saltwater disposal/Midstream	32,297		
Total capital investment	$ 577,153		

The Permian Basin encompasses west Texas and southeast New Mexico. Cimarex's Permian Basin efforts are located in the western half of the Permian Basin known as the Delaware Basin. In 2020, our development activity primarily focused on the Wolfcamp shale formation in Culberson and Reeves Counties in Texas and Lea and Eddy Counties in New Mexico. The Wolfcamp is being developed with horizontal wells primarily using two-mile laterals.

The Permian Basin produced 184.0 MBOE per day in 2020, which was 73% of our total company production. Total production from the region decreased 3% in 2020 from 2019. In 2020, we invested $503.3 million, or 92%, of our total E&D investment, in the Permian Basin.

Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2020 in the Mid-Continent was focused in the Woodford shale and the Meramec horizon, both in Oklahoma.

During 2020, production from the Mid-Continent averaged 68.1 MBOE per day, or 27% of total company production. Total production from the region decreased 22% in 2020 as compared to 2019. In 2020, we invested $40.8 million, or 8% of our total E&D investment, in the Mid-Continent.

Drilling Activity

In 2020, we completed or participated in the completion of 149 gross (51.0 net) productive wells, of which we operated 61 gross (47.6 net) wells. At year-end, we were in the process of drilling or participating in 10 gross (4.3 net) wells and there were 77 gross (39.6 net) wells waiting on completion.

We completed the following number of development wells in the years indicated in the table below. During these years, we completed no exploratory wells.

	Wells Completed					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	149	51.0	289	90.2	349	122.1
Dry	2	1.5	2	1.9	—	—
Total	151	52.5	291	92.1	349	122.1

At December 31, 2020, we owned an interest in 10,061 gross (2,765 net) productive oil and gas wells. We had working interests in the following number of productive wells by region as of December 31, 2020:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,876	1,449	869	175
Permian Basin	705	310	4,495	827
Other	103	3	13	1
	4,684	1,762	5,377	1,003

Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2020.

	Acreage					
	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Kansas	16,822	16,782	—	—	16,822	16,782
Oklahoma	156,179	47,624	774,542	306,849	930,721	354,473
Texas	22,544	9,317	108,536	52,676	131,080	61,993
	195,545	73,723	883,078	359,525	1,078,623	433,248
Permian Basin						
New Mexico	123,460	49,306	175,144	120,106	298,604	169,412
Texas	45,962	26,971	222,445	134,233	268,407	161,204
	169,422	76,277	397,589	254,339	567,011	330,616
Other						
Arizona	2,097,841	2,097,841	17,212	17,207	2,115,053	2,115,048
California	383,487	383,487	—	—	383,487	383,487
Colorado	38,092	18,767	43,459	1,642	81,551	20,409
Gulf of Mexico	20,000	11,000	26,345	6,381	46,345	17,381
Nevada	1,007,167	1,007,167	440	1	1,007,607	1,007,168
New Mexico	1,640,153	1,634,459	18,538	2,436	1,658,691	1,636,895
Texas	6,487	2,616	10,831	4,866	17,318	7,482
Utah	66,380	58,933	42,458	1,445	108,838	60,378
Wyoming	79,640	18,557	51,947	3,980	131,587	22,537
Other	235,647	182,286	21,770	4,827	257,417	187,113
	5,574,894	5,415,113	233,000	42,785	5,807,894	5,457,898
	5,939,861	5,565,113	1,513,667	656,649	7,453,528	6,221,762

The table below summarizes by year and region our undeveloped acreage expirations in the next five years. In most cases, the drilling of a commercial well will hold the acreage beyond the expiration.

	Acreage									
	2021		2022		2023		2024		2025	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	8,074	6,583	3,101	1,946	1,233	465	420	330	—	—
Permian Basin	10,835	4,878	4,394	1,978	960	960	40	40	—	—
Other	124,148	120,590	34,413	31,592	6,840	5,729	1,302	1,241	—	—
	143,057	132,051	41,908	35,516	9,033	7,154	1,762	1,611	—	—
% of total undeveloped acreage	2.4	2.4	0.7	0.6	0.2	0.1	—	—	—	—

At December 31, 2020, we had no proved undeveloped reserves booked on undeveloped acreage that were scheduled for development beyond the expiration dates of the undeveloped acreage.

Title to Oil and Gas Properties

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect, or acquire proved properties. We believe title to our properties is good and defensible, and is in accordance with industry standards. Nevertheless, we are involved in title disputes from time to time that result in litigation. Our oil and gas properties are subject to customary royalty interests, liens incidental to operating agreements, tax liens, and other burdens and minor encumbrances, easements, and restrictions.

Competition

The oil and gas industry is highly competitive, particularly for prospective undeveloped leases and purchases of proved reserves. There is also competition for rigs and related equipment used to drill for and produce oil and gas, however, to a lesser extent in the current market environment. Our competitive position also is highly dependent on our ability to recruit and retain geological, geophysical, and engineering expertise. We compete for prospects, proved reserves, oil-field services, and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human, and technological resources than we do.

We compete with integrated, independent, and other energy companies for the sale and transportation of our oil, gas, and NGLs to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial, and residential consumers. Many of these competitors have greater financial and human resources than we do. The effect of these competitive factors cannot be predicted.

Proved Reserves Estimation Procedures

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with the SEC's rules for reporting oil and gas reserves. Our reserve definitions conform with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the company. The primary objective of our Corporate Reservoir Engineering group is to maintain accurate forecasts on all properties of the company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC. This separation of function and responsibility is a key internal control.

Cimarex engineers are responsible for estimates of proved reserves. Corporate engineers interact with the exploration and production departments to ensure all available engineering and geologic data is taken into account prior to establishing or revising an estimate. After preparing the reserves update, the corporate engineers review their recommendations with the Vice President of Corporate Engineering. After approval from the Vice President of Corporate Engineering, the revisions are entered into our reserves database by the engineering technician.

During the course of the year, the Vice President of Corporate Engineering presents summary reserves information to senior management and to our Board of Directors for their review. From time to time, the Vice President of Corporate Engineering also will confer with senior management, including the Chief Executive Officer, regarding specific reserves-related issues. In addition, Corporate Reservoir Engineering maintains a set of basic guidelines and procedures to ensure that critical checks and reviews of the reserves database are performed on a regular basis.

Together, these internal controls are designed to promote a comprehensive, objective, and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, performed an independent evaluation of our estimated net reserves representing greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2020. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 10 years of experience in oil and gas reservoir studies and reserves evaluations.

The technical employee primarily responsible for overseeing the oil and gas reserves estimation process is Cimarex's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 26 years of practical experience in oil and gas reservoir evaluation. He has been directly involved in the annual reserves reporting process of Cimarex since 2002 and has served in his current role for the past 16 years.

Marketing

Our oil and gas production is sold under an assortment of short-term and long-term arrangements at market-responsive prices. We sell our oil at prices tied to NYMEX pricing with customary adjustments for quality and location. Our gas sales are tied to either monthly or daily index pricing and we sell the majority of our NGLs at prices tied to monthly index prices less an applicable transportation and fractionation cost.

We sell our oil, gas, and NGLs to a broad portfolio of customers, including major energy companies, pipeline companies, local distribution companies, and other end-users. In 2020, we made sales to two customers that each amounted to 10% or more of our consolidated revenues for 2020. Sales to those two customers accounted for 26% and 23%, respectively, of our consolidated revenues for 2020. If any one of our major customers were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production. If multiple significant customers were to discontinue purchasing our production, we believe there could be some initial challenges, but we have ample alternative markets to handle any sales disruption.

We regularly monitor the credit worthiness of all our customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary. Historically, losses associated with uncollectible receivables have not been significant.

Government Regulation

Oil and gas production and transportation is subject to extensive federal, state, and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a significant adverse effect on our operations or financial condition. In recent years, we have been most directly impacted by federal and state environmental regulations and energy conservation rules. We are also impacted by federal and state regulation of pipelines and other oil and gas transportation systems.

The states in which we conduct operations establish requirements for drilling permits, the method of developing fields, the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws include requirements for waste prevention, establish limits on the maximum rate of production from wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability of production.

Environmental Regulation. Various federal, state, and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development, and production operations, which consequently impact our operations and costs. These laws and regulations govern, among other things, emissions into the atmosphere, discharges of pollutants into waters, underground injection of waste water, the generation, storage, transportation, and disposal of waste materials, and protection of public health, natural resources, and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

Cimarex is committed to environmental protection and believes we are in material compliance with applicable environmental laws and regulations. We obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. Expenditures are required to comply with environmental regulations. These costs are a normal, recurring expense of operations and not an extraordinary cost of compliance with current government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations, we are unable to predict with any reasonable degree of certainty any potential delays in development plans that could arise, or our future costs of complying with governmental requirements. We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water, or other substances as well as additional coverage for certain other pollution events.

Gas Gathering and Transportation. The Federal Energy Regulatory Commission (“FERC”) requires interstate gas pipelines to provide open access transportation. FERC also enforces the prohibition of market manipulation by any entity, and the facilitation of the sale or transportation of natural gas in interstate commerce. Interstate pipelines have implemented these requirements, providing us with additional market access and more fairly applied transportation services and rates. FERC continues to review and modify its open access and other regulations applicable to interstate pipelines.

Under the Natural Gas Policy Act (“NGPA”), natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes “gathering” under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering systems meet the test for non-jurisdictional “gathering” systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

In addition to using our own gathering facilities, we may use third-party gathering services or interstate transmission facilities (owned and operated by interstate pipelines) to ship our gas to markets.

Additional proposals and proceedings that might affect the oil and gas industry are pending before the U.S. Congress, FERC, Bureau of Land Management (“BLM”), U.S. Environmental Protection Agency (“EPA”), state legislatures, state agencies, local governments, and the courts. We cannot predict when or whether any such proposals may become effective and what effect they will have on our operations.

We do not anticipate that compliance with existing federal, state, and local laws, rules, or regulations will have a material adverse effect upon our capital expenditures, earnings, or competitive position.

Federal and State Income and Other Local Taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws, as well as other local tax regulations involving ad valorem, personal property, franchise, severance, and other excise taxes. We have considered the effects of these provisions on our operations and do not anticipate that they will cause any material undisclosed impact on our capital expenditures, earnings, or competitive position.

Human Capital Resources

As of December 31, 2020, Cimarex employed 747 highly talented and committed individuals across our field operations and business offices. Our employee base was reduced in 2020 by approximately 24% from December 31, 2019 as a result of a voluntary early retirement incentive program we offered to employees who met certain eligibility criteria in the first quarter of 2020 and an involuntary reduction in workforce program we carried out in the third quarter of 2020. These programs were initiated to ensure the size of our workforce is consistent with our expected future activity levels.

Fostering a healthy culture built upon transparency, trust, collaboration, and results is an area of emphasis for Cimarex leadership. Key areas of Cimarex Human Capital focus are:

Health and Safety

The health and safety of every Cimarex employee is our top priority. In 2020, Cimarex hired a third-party to conduct an extensive safety assessment so that we could determine key areas of focus and improvement. The assessment results have helped us direct our efforts to improve our safety record from positive to “best in class”. We created an Executive Safety Council made up of senior operational leadership to take action and continue building our safety culture. Throughout COVID-19, Cimarex has implemented policies and practices to keep our offices and field operations free from transmission of the virus. The Cimarex COVID-19 task force was formed in February 2020 and meets weekly to actively manage decisions and communication. We have provided significant remote work flexibility and extensive use of video conferencing technology, have eliminated in-person group gatherings, limited all business-related travel to essential only, and have implemented office and field employee protocols requiring masks, physical distancing, and cleaning.

Leadership Development, Succession Planning, and Talent Management

The CEO and Chief Human Resources Officer are critically focused on the next generation of Cimarex’s senior leadership. Formal and informal development, mentoring, and coaching of high potential staff is a recognized role for all of our executive leaders. We also expose our Board of Directors to Cimarex’s high potential future leaders which facilitates more informed discussions during our annual succession planning. We consistently refresh our talent base with a robust college internship and full-time recruiting program. We continued our full scale college recruiting program in 2020 during the COVID-19 downturn and enabled all of our interns to work and be mentored remotely.

Compensation and Benefits

Cimarex’s compensation programs are intended to attract, retain, and motivate top talent and reward great results with top pay. We align short and long-term incentives of our executives and the broader workforce with both company results and shareholder interests. Cimarex also provides top-notch health care and retirement benefits so that our employees can focus on excellence in their work. For example, Cimarex contributes more than 90% of the total cost of employee health care benefits.

Diversity and Inclusion

Cimarex is working to become more diverse and inclusive so that every employee can contribute to their fullest potential and can confidently share ideas that drive value. Through a thorough regular pay equity analysis we ensure that all employees are paid equitably. The Cimarex Board of Directors contains diverse backgrounds and perspectives, in addition to gender and ethnic diversity. Female employees constitute 29% of our total workforce and in 2019, female leaders at Cimarex initiated a women’s network which expanded in 2020 and now includes formal mentoring. We currently are defining 2021 objectives to improve our hiring, development, and promotion of ethnic minorities.

Executive Officers of the Registrant

See Part III, Item 10, Directors, Executive Officers and Corporate Governance for information regarding our executive officers as of February 23, 2021.

ITEM 1A. RISK FACTORS

The following risks and uncertainties, together with other information set forth in this Form 10-K for the year ended December 31, 2020, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. There are unknown risks and uncertainties, or risks we currently deem immaterial, that also may impair our business operations or financial condition, which in turn could negatively impact the value of our securities. While many of the risks below relate to the COVID-19 pandemic, given the unpredictable and unprecedented nature of the pandemic, it is impossible to identify all potential risks and estimate the ultimate adverse impact on our business. The COVID-19 pandemic, and mutations of the virus or other outbreaks of communicable diseases, may amplify the risks disclosed in this Form 10-K. These risk factors speak only as of the filing date of this Form 10-K and are subject to change without notice as we cannot predict all risks relating to this quickly evolving set of events.

Outbreaks of communicable diseases could adversely affect our business, financial condition, and results of operations.

Global or national health concerns, including a widespread outbreak of contagious diseases, can negatively impact the global economy, reduce demand and lower pricing for oil, gas, and NGLs, lead to operational disruptions and limit our ability to execute our business plan, which could materially and adversely affect our business, financial condition, and results of operations. For example, the current COVID-19 pandemic, including the measures being taken to address and limit its spread, have adversely affected the economies and financial markets of many countries, resulting in an economic downturn that has negatively impacted, and may continue to negatively impact, global demand and prices for oil, gas, and NGLs. If the COVID-19 outbreak worsens, we also may experience further disruptions to the commodities markets, as well as disruptions to the equipment supply chains and the availability of our workforce as well as the workforces of contractors and regulators, any of which could adversely affect our ability to conduct our business and operations. The numerous uncertainties regarding the COVID-19 pandemic, such as the ultimate geographic spread, duration, and severity of the outbreak, the impact of mutations of the virus, and governmental restrictions and business closures, prevent us from being able to fully assess potential impacts on our business and operations. However, these uncertainties could materially and adversely affect our business, financial condition, and results of operations.

The adoption of climate change legislation or regulations restricting emission of greenhouse gases, investor pressure concerning climate-related disclosures, and lawsuits could result in increased operating costs and reduced demand for the oil and gas we produce as well as reductions in the availability of capital.

Studies have found that emission of certain gases, commonly referred to as greenhouse gases (“GHGs”), impact the earth’s climate. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict emissions of GHGs. On January 20, 2021, President Biden’s first day in office, he signed an executive order on climate action and reconvened an interagency working group to establish interim and final social costs of three GHGs: carbon dioxide, nitrous oxide, and methane. Carbon dioxide is released during the combustion of fossil fuels, including oil, natural gas, and NGLs, and methane is a primary component of natural gas. The Biden administration stated it will use updated social cost figures to inform federal regulations and major agency actions and to justify aggressive climate action as the United States moves toward a “100% clean energy” economy with net-zero GHG emissions. These actions could result in increased costs and reduced demand for our products. Also on January 20, 2021, the Acting Secretary of the Interior issued an order suspending for 60 days the authority for Department Bureaus and Offices to, among other things, grant rights-of-way or easements, which are necessary for pipelines and roads used in oil, gas, and NGL production, and to issue new permits to drill. During this 60-day period, these permits, which were typically approved at the regional office level, can only be approved by the Secretary of Interior, Deputy Secretary, Solicitor, or various Assistant Secretaries. These new requirements may lead to delays in obtaining approvals necessary for our operations.

In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the Federal Clean Air Act that establish Prevention of Significant Deterioration ("PSD") and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD and/or Title V permits under EPA's GHG Tailoring Rule for their GHG emissions also may be required to meet "Best Available Control Technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and gas production facilities on an annual basis, which includes certain of our operations. In recent proposed rulemaking, EPA is widening the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems, and transmission pipelines.

While the U.S. Congress has considered legislation to reduce emissions of GHGs in recent years, it has not adopted any significant GHG legislation. This is expected to change with the Democratic Party now in control of the House of Representatives, the Senate, and the office of the President. In the absence of federal GHG legislation, a number of state and regional efforts have emerged, aimed at tracking and/or reducing GHG emissions through cap-and-trade programs, which typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs. Any future laws or regulations that require reporting of, or otherwise limit emissions of, GHGs from our equipment and operations could require us to both develop and implement new practices aimed at reducing GHG emissions, such as emissions control technologies, and monitor and report GHG emissions associated with our operations, any of which could increase our operating costs and could adversely affect demand for the oil and gas that we produce. At this time, it is not possible to quantify the impact of such future laws and regulations on our business.

Several policy makers and political candidates have made, or expressed support for, a variety of more comprehensive proposals, such as cap-and-trade or carbon tax programs, as well as the more sweeping "green new deal" resolutions the U.S. Congress introduced in early 2019. As generally proposed, the "green new deal" includes (i) a cap-and-trade program capping overall GHG emissions on an economy-wide basis and requiring major sources of GHG emissions or major fuel producers to acquire and surrender emission allowances and (ii) a carbon tax, which would impose taxes based on emissions from our operations and the downstream uses of our products. The "green new deal" calls for a 10-year national mobilization effort to, among other things, transition 100% of the U.S. power demand to zero-emission sources and overhaul the U.S. transportation systems so that GHG emissions are eliminated as much as is technologically feasible. The enactment of any such legislation would have a material adverse effect on our business and operations.

We are subject to various climate-related risks.

The following is a summary of potential climate-related risks that could adversely affect us:

Transition Risks. Transition risks are related to the transition to a lower-carbon economy and include policy and legal, technology, and market risks.

Policy and Legal Risks. Policy risks include actions that seek to lessen activities that contribute to adverse effects of climate change or to promote adaptation to climate change. These policy actions could be accelerated by the recent change from a Republican to a Democratic party in control of Congress and the Presidency. Examples of policy actions that would increase the costs of our operations or lower demand for our oil and gas include implementing carbon-pricing mechanisms, shifting energy use toward lower emission sources, adopting energy-efficiency solutions, encouraging greater water efficiency measures, and promoting more sustainable land-use practices. Policy actions also may include restrictions or bans on oil and gas activities, like the January 2021 Presidential and Secretarial orders, and the potential banning of hydraulic fracturing, which could lead to write-downs or impairments of our assets. Legal risks include potential lawsuits claiming failure to mitigate impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks.

Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil, gas, and NGL operations constitute a public nuisance under federal and state law. Private individuals or public entities also could attempt to enforce environmental laws and regulations against us and could seek personal injury and property damages or other remedies. While we are currently not a party to any such litigation, unfavorable rulings against us in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Technology Risks. Technological improvements or innovations that support the transition to a lower-carbon, more energy efficient economic system may have a significant impact on Cimarex. The development and use of emerging technologies in renewable energy, battery storage, and energy efficiency may lower demand for oil and gas, resulting in lower prices and revenues, and higher costs. In addition, many automobile manufacturers have announced plans to shift production from internal combustion engine to electric powered vehicles, and states and foreign countries have announced bans on sales of internal combustion engine vehicles beginning as early as 2025, which would reduce demand for oil.

Market Risks. Markets could be affected by climate change through shifts in supply and demand for certain commodities, especially carbon-intensive commodities such as oil and gas and other products dependent on oil and gas. Lower demand for our oil and gas production could result in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to less carbon-intensive industries and alternative energy industries. In addition, investment advisers, banks, and certain sovereign wealth, pension, and endowment funds recently have been promoting divestment of investments in fossil fuel companies and pressuring lenders to limit funding to companies engaged in the extraction, production, and sale of oil and gas. In October 2020, JP Morgan Chase & Co. announced that it was adopting a financing commitment that is aligned to the goals of the Paris climate accord of 2015 (the “Paris Agreement”). Other banks have made climate-related pledges for various causes, such as stopping the financing of Arctic drilling and coal companies. These initiatives by activists and banks, including certain banks in our credit facility, could interfere with our business activities, operations, and ability to access capital.

Reputation Risk. Climate change is a potential source of reputational risk, which is tied to changing customer or community perceptions of an organization’s contribution to, or detraction from, the transition to a lower-carbon economy. These changing perceptions could lower demand for our oil and gas production, resulting in lower prices and lower revenues as consumers avoid carbon-intensive industries, and could also pressure banks and investment managers to shift investments and reduce lending as described above.

Physical Risks. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts such as supply chain disruption and also could include changes in water availability, sourcing, and quality, which could impact drilling and completions operations. These physical risks could cause increased costs, production disruptions, lower revenues, and substantially increase the cost or limit the availability of insurance.

Our hydraulic fracturing activities are subject to risks that could negatively impact our operations and profitability.

We use hydraulic fracturing for the completion of almost all of our wells. Hydraulic fracturing is a process that involves pumping fluid and proppant at high pressure into a hydrocarbon bearing formation to create and hold open fractures. Those fractures enable gas or oil to move through the formation’s pores to the well bore. Typically, the fluid used in this process is primarily water. In areas where hydraulic fracturing is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

Certain federal agencies have asserted regulatory authority over aspects of the hydraulic fracturing process. The EPA, for example, has issued regulations under the federal Clean Air Act establishing performance standards for oil and gas activities, including standards for the capture of air emissions released during hydraulic fracturing. In 2016, the EPA finalized regulations that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants and issued a report finding that certain aspects of hydraulic fracturing, such as water withdrawals and wastewater management practices, could impact water resources. The BLM previously finalized regulations to regulate hydraulic fracturing on federal lands but subsequently issued a repeal of those regulations in 2017. States in which we operate also have adopted, or have stated intentions to adopt, laws or regulations that mandate further restrictions on hydraulic fracturing, such as imposing more stringent permitting, disclosure and well-construction requirements on hydraulic fracturing operations and establishing standards for the capture of air emissions released during hydraulic fracturing. In addition to states, local land use restrictions, such as city ordinances, may restrict drilling in general or hydraulic fracturing in particular.

Moreover, as stated above, policy makers have proposed implementing stricter restrictions on hydraulic fracturing, including banning the process outright. For example, it is expected that the Biden administration will attempt to limit or prohibit hydraulic fracturing on federal lands, which would adversely impact our operations in the Permian Basin, as well as other areas where we operate under federal leases. As of December 31, 2020, approximately 3% of our total net leasehold resides on federal lands, and approximately 31% of our total net leasehold in the Permian Basin is located on federal lands. Although it is not possible at this time to predict the outcome of any restrictive proposals, any new restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could potentially result in increased compliance costs, delays or cessation in development or other restrictions on our operations.

Any of the above factors could have a material adverse effect on our financial position, results of operations, or cash flows and could make it more difficult, costly or impossible for us to perform hydraulic fracturing to stimulate production from future wells. Restrictions on hydraulic fracturing also could reduce the amount of oil and gas that we are ultimately able to produce from our reserves

Oil, gas, and NGL prices fluctuate due to a number of factors beyond our control, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.

Oil, gas, and NGL markets are volatile. We cannot predict future prices. The prices we receive for our production heavily influence our revenue, profitability, access to capital, and future rate of growth. The prices we receive depend on numerous factors beyond our control. These factors include, but are not limited to, changes in domestic and global supply and demand for oil, gas, and NGLs, the level of domestic and global oil, gas, and NGL exploration and production activity, pipeline capacity constraints limiting takeaway and increasing basis differentials, geopolitical instability, the actions of the Organization of the Petroleum Exporting Countries ("OPEC") and other cooperating countries, global or national health concerns including the outbreak of pandemic or contagious diseases such as COVID-19, weather conditions, technological advances affecting energy consumption, governmental regulations and taxes, changes in administrations and legislative control at federal and state levels, and the price and technological advancement of alternative fuels. Demand for oil, gas, and NGLs has severely diminished because of the COVID-19 pandemic, and the resulting restrictions on and closure of factories and businesses, significant travel restrictions and stay-at-home orders, causing lower commodity prices. Oil prices also can decrease if OPEC increases supply, as it did in the first quarter of 2020 at a time when global demand was decreasing. If any of these conditions persist, our financial results could be adversely affected by the reduction in production revenues, and our inability to collect amounts owed by purchasers of our production.

Our proved oil and gas reserves and production volumes will decrease unless we replace those reserves with new discoveries or acquisitions. Accordingly, for the foreseeable future, we expect to make capital investments for the exploration and development of new oil and gas reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations, our revolving credit facility, and proceeds from the sale of senior notes or equity. Low commodity prices reduce our cash flow, and the amount of oil and gas that we can economically produce and may cause us to curtail, delay, or defer certain exploration and development projects. Moreover, low commodity prices may impact our ability to raise additional debt or equity capital to fund acquisitions.

If commodity prices remain at current levels or decline further, we will be required to take additional write-downs of the carrying value of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our oil and gas properties for possible impairment. We recognized ceiling test impairments totaling $1.64 billion during the year ended December 31, 2020 and $618.7 million during the year ended December 31, 2019. The impairments resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net cash flows from proved reserves. If commodity pricing conditions stay at current levels or decline further, we may incur further ceiling test impairments in future quarters. Because the ceiling calculation uses trailing twelve-month average commodity prices, the effect of declining prices is a lower ceiling value each quarter. This results in ongoing impairments each quarter until prices stabilize or improve. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

Ineffective internal controls could impact our business and financial results.

Our internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed, and we could fail to meet our financial reporting obligations.

U.S. or global financial markets may impact our business and financial condition.

A credit crisis or other turmoil in the U.S. or global financial system may have a negative impact on our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. This could have an impact on our flexibility to react to changing economic and business conditions. Deteriorating economic conditions, including those resulting from the COVID-19 pandemic, could have a negative impact on our lenders, our hedging counterparties, the purchasers of our oil and gas production, and the working interest owners in properties we operate, causing them to fail to meet their obligations to us.

Failure to economically replace oil and gas reserves could negatively affect our financial results and future rate of growth; exploration and development involves numerous risks.

In order to replace the reserves depleted by production and to maintain or increase our total proved reserves and overall production levels, we must either locate and develop new oil and gas reserves or acquire proved reserves from others. This requires significant capital expenditures and can impose reinvestment risk for us, as we may not be able to continue to replace our reserves economically. While we occasionally may seek to acquire proved reserves, our main business strategy is to grow through exploration and drilling. Without successful exploration and development, our reserves, production, and revenues could decline rapidly, which would negatively impact the results of our operations.

Exploration and development involves numerous risks, including new governmental regulations and the risk that we will not discover any commercially productive oil or gas reservoirs. Additionally, it can be unprofitable, not only from drilling dry holes but also from drilling productive wells that do not return a profit because of insufficient reserves or declines in commodity prices.

Our drilling operations may be curtailed, delayed, or canceled for many reasons. Factors, in addition to those enumerated above, include unforeseen poor drilling conditions, title problems, unexpected pressure irregularities, equipment failures, accidents, adverse weather conditions, and the cost of, or shortages or delays in the availability of, drilling and completion services could negatively impact our drilling operations.

Our proved reserve estimates may be inaccurate and future net cash flows are uncertain.

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. Refer to **CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS** in Part I of this report. Among others, changes in any of the following factors may cause actual results to vary considerably from our estimates:

- oil, gas, and NGL prices;
- timing of development expenditures;
- amount of required capital expenditures and associated economics;
- recovery efficiencies, decline rates, drainage areas, and reservoir limits;
- anticipated reservoir and production characteristics and interpretations of geologic and geophysical data;
- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- governmental regulation;
- access to assets restricted by local government action;
- operating costs;
- property, severance, excise, and other taxes incidental to oil and gas operations;
- workover and remediation costs; and
- federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, performed an independent evaluation of our estimated net reserves representing greater than 80% of the total future net revenue discounted at 10%, as of December 31, 2020.

The cash flow amounts referred to in this filing should not be construed as the current market value of our proved reserves. In accordance with SEC guidelines, the estimated discounted net cash flow from proved reserves is based on the average of the previous twelve months' first-day-of-the-month prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

The inability to obtain rights-of-way from federal agencies may lead to our inability to transport our oil, gas, and NGLs from drilled wells for which we have spent drilling and completion capital and deprive us of revenues from sales of those products.

The inability for us or our third party gatherers to obtain rights-of-way to build gathering lines to move our produced oil, gas, and NGLs from our wells to markets could prevent us from receiving production revenues after expending capital on drilling and completing those wells. This is of particular concern on federal lands for the reasons noted above in, "*The adoption of climate change legislation or regulations restricting emission of greenhouse gases, investor pressure concerning climate-related disclosures, and lawsuits could result in increased operating costs and reduced demand for the oil and gas we produce as well as reductions in the availability of capital*." The Biden administration's restrictions may lead to delays in obtaining approvals necessary for our operations and lead to losses.

We may be subject to information technology system failures, network disruptions, and breaches in data security and our business, financial position, results of operations, and cash flows could be negatively affected by such security threats and disruptions.

As an oil and gas producer, we face various cybersecurity threats. Cyberattacks are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, and "ransomware" attacks where data is locked unless a payment is made, any of which could have an adverse effect on our reputation, business, financial condition, results of operations, or cash flows. While we have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. In addition to cyberattacks, other information system failures and network disruptions could have a material adverse effect on our ability to conduct our business. We could experience system failures due to power or telecommunications failures, human error, natural disasters, fire, sabotage, hardware or software malfunction or defects, computer viruses, intentional acts of vandalism or terrorism and similar acts or occurrences. Such system failures could result in the unanticipated disruption of our operations, communications, or processing of transactions, as well as loss of, or damage to, sensitive information, facilities, infrastructure and systems essential to our business and operations, the failure to meet regulatory standards and the reporting of our financial results, and other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations, and cash flows.

A cyberattack involving our information systems and related infrastructure, or those of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

- unauthorized access to seismic data, reserves information, or other strategic or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- data corruption or operational disruption of production-related infrastructure could result in a loss of production, or an accidental discharge;

- a cyberattack on a vendor or service provider could result in supply chain disruptions, which could delay or halt our major development projects;

- a cyberattack on third-party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues; and

- a cyberattack on our accounting or accounts payable systems could expose us to liability to employees and third parties if their personal identifying information is obtained.

These events could damage our reputation and lead to monetary losses, or a loss of business, which could have a material adverse effect on our financial condition, results of operations, or cash flows.

While management has taken steps to address these concerns by implementing network security and internal control measures to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure, our implementation of such procedures and controls may result in increased costs, and there can be no assurance that a system failure or data security breach will not occur and have a material adverse effect on our business, financial condition, and results of operations. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity or information technology infrastructure vulnerabilities. With large numbers of employees (industry-wide and at Cimarex) working remotely during the COVID-19 pandemic, there may be heightened vulnerability to cyberattacks.

Our business depends on oil and gas pipeline and transportation facilities, some of which are owned by others.

In addition to the existence of adequate markets, our oil and gas production depends in large part on the proximity and capacity of pipeline systems, as well as storage, processing, transportation, and fractionation facilities, most of which are owned by third parties. Oil, refined products, and gas storage reached historically high levels due to reduced demand from the COVID-19 pandemic, which places price pressure across all commodities. We do not anticipate the inability to transport our commodities; however, should that occur, our production could be curtailed, which would impact drilling plans. Curtailments of production could lead to payment being required where we fail to deliver oil, gas, and NGLs to meet minimum volume commitments. These availability and capacity issues are more likely to occur in remote areas with less established infrastructure, such as our Delaware Basin area where we have significant oil and gas production. Any of these availability or capacity issues, whether resulting from the COVID-19 pandemic, construction delays, government restrictions, such as occurred with the revocation of the permit for the Keystone XL Pipeline on the first day of the Biden administration, weather, fire, or other reasons, could negatively affect our operations and revenues.

Commodity price derivative transactions may limit our potential gains and involve other risks.

To limit our exposure to price risk, we enter into derivative agreements from time to time. Commodity price derivatives limit volatility and increase the predictability of a portion of our cash flow. These transactions also limit our potential gains when oil and gas prices exceed the prices established by the derivatives.

In certain circumstances, derivative transactions may expose us to the risk of financial loss, including instances in which:

- the counterparties to our derivative agreements fail to perform;
- there is a sudden unexpected event that materially increases oil and gas prices; or
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the derivative agreement.

Because we account for derivative contracts under mark-to-market accounting, during periods we have derivative transactions in place, we expect continued volatility in derivative gains and losses on our statement of operations as changes occur in the relevant price indexes.

Competition in our industry is intense and many of our competitors have greater financial and technological resources.

We operate in the competitive area of oil and gas exploration and production. Many of our competitors are large, well-established companies that have larger operating staffs and greater capital resources. These competitors may be willing to pay more for exploratory prospects and productive oil and gas properties. They may also be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit.

Because our activity is concentrated in areas of heavy industry competition, there is heightened demand for personnel, equipment, power, services, facilities, and resources, resulting in higher costs than in other areas. Such intense competition also could result in delays in securing, or the inability to secure, the personnel, equipment, power, services, resources, or facilities necessary for our development activities, which could negatively impact our production volumes. In remote areas vendors also can charge higher rates due to the inability to attract employees to those areas and the vendors' ability to deploy their resources in easier-to-access areas.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures, and cement failures. Other risks include theft, vandalism, and environmental hazards such as gas leaks, oil and produced water spills, and discharges of toxic gases. Any of these risks can cause substantial losses or costs resulting from:

- injury or loss of life;
- damage to, loss of, or destruction of, property and equipment;
- pollution and other environmental damages;
- regulatory investigations, civil litigation, and penalties;
- damage to our reputation; and
- suspension of our operations.

In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease.

We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all losses or damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of our existing insurance coverage. The occurrence of an event that is not fully covered by our insurance could harm our financial condition and results of operations. The cost of insurance may increase, and the availability of insurance may decrease, as a result of climate change or other factors.

We may not be able to generate enough cash flow to meet our debt obligations.

As of December 31, 2020, our long-term debt consisted of $750 million of 4.375% senior notes due in 2024, $750 million of 3.90% senior notes due in 2027, and $500 million of 4.375% senior notes due in 2029. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, capital expenditures, operating expenses, and contractual commitments.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, results of operations, and other factors, many of which are beyond our control. The current COVID-19 pandemic initially resulted in limited availability of public debt markets. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowing under our existing revolving credit facility bears interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. Our cash flow has been impacted by the reduced commodity prices and lower production resulting from diminished demand caused by the COVID-19 pandemic. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets; or
- restructuring or refinancing debt.

We may be unable to complete any such strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations or contractual commitments, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indenture governing our senior notes and our credit agreement contain various restrictive covenants that may limit management’s discretion in certain respects. In particular, these agreements may limit our ability to, among other things:

- create certain liens; or
- consolidate, merge, or transfer all, or substantially all, of our assets and our restricted subsidiaries.

In addition, our revolving credit agreement requires us to maintain a total debt-to-capitalization ratio (as defined in the credit agreement) of not more than 65%. While we were in compliance with this covenant at December 31, 2020, net losses in the future driven by ceiling test impairments could cause us to exceed this ratio.

If we fail to comply with the restrictions in the indenture governing our senior notes or the agreement governing our credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be limited or eliminated as a result of future legislation.

On December 22, 2017, the United States enacted H.R.1, commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. H.R.1, among other things, includes changes to U.S. federal tax rates, imposes new limitations on the utilization of net operating losses and the deductibility of interest and executive compensation, allows for the expensing of capital expenditures, and eliminates the corporate Alternative Minimum Tax. In addition, various proposals have been made recommending the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. While the tax law changes approved in December 2017 did not eliminate any of these incentives, new legislation may be introduced in Congress which would implement many of these proposals. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could have an adverse effect on our financial position, results of operations, and cash flows, including the payment of cash taxes earlier than expected.

We are involved in various legal proceedings, the outcome of which could have an adverse effect on our liquidity.

In the normal course of business, we are involved with various lawsuits and related disputed claims, including but not limited to claims concerning title, validity of leases, royalty payments, environmental issues, personal injuries, labor issues, and contractual issues. Although we currently believe the resolution of these lawsuits and claims, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations, our assessment of our current litigation and other legal proceedings could change with the discovery of facts not presently known to us or as a result of determinations by judges, juries, or other finders of fact that are not in accord with our evaluation of the possible liability or outcome of such proceedings. Therefore, there can be no assurance that outcomes of future legal proceedings would not have an adverse effect on our liquidity and capital resources.

We are subject to complex laws and regulations that can adversely affect the cost, manner, and feasibility of doing business.

As an owner, lessee, or operator of oil and gas properties, we are subject to various complex, stringent, and constantly evolving environmental laws and regulations. Our operations inherently create the risk of environmental liability to the government and private parties stemming from our use, generation, handling, and disposal of water and waste materials, as well as the release of hydrocarbons or other substances into the air, soil, or water. The environmental laws and regulations to which we are subject impose numerous obligations applicable to our operations, including: the acquisition of permits before conducting regulated activities associated with drilling for and producing oil and gas; the restriction of types, quantities, and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, waters of the United States, and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits (for the reasons described elsewhere in these Risk Factors), which may delay or interrupt our operations and limit our growth and revenue. These permits and other regulatory approvals also may be negatively impacted by COVID-19 restrictions on regulatory employees responsible for regulatory approvals.

Liabilities under certain environmental laws can be joint and several and may in some cases be imposed regardless of fault on our part such as where we own a working interest in a property operated by another party. We also could be held liable for damages or remediating lands or facilities previously owned or operated by others regardless of whether such contamination resulted from our own actions and regardless if we were in compliance with all applicable law at the time. Further, claims for damages to persons or property, including natural resources, may result from the environmental, health, and safety impacts of our operations. Because these environmental risks generally are not fully insurable and can result in substantial costs, such liabilities could have a material adverse effect on both our financial condition and operations.

Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, pollutants, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, discharge, transportation, and disposal of pollutants and solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The most significant of these environmental laws are as follows:

- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as “CERCLA” or the “Superfund law,” and comparable state laws, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;

- The Oil Pollution Act of 1990 (“OPA”), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;

- The Resource Conservation and Recovery Act (“RCRA”), as amended, and comparable state statutes, which governs the treatment, storage, and disposal of solid waste;

- The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (“CWA”), which governs the discharge of pollutants, including natural gas wastes, into federal and state waters;

- The Safe Drinking Water Act (“SDWA”), which governs the disposal of wastewater in underground injection wells; and

- The Clean Air Act (“CAA”) which governs the emission of pollutants into the air.

We believe we are in substantial compliance with the above requirements and related state and local laws and regulations. We also believe we hold all necessary and up-to-date permits, registrations, and other authorizations required under such laws and regulations. Although the current costs of managing our wastes as they presently are classified are reflected in our budget, any legislative or regulatory reclassification of oil and gas exploration and production wastes could increase our costs to manage and dispose of such wastes and have a material adverse effect on our financial condition and operations.

Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.

The Federal Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and gas leases in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons.

On March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico, and Oklahoma, where we conduct operations, as a threatened species under the ESA. Listing of the lesser prairie chicken as a threatened species imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm, or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. We entered into a voluntary Candidate Conservation Agreement ("CCA") with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the lesser prairie chicken.

On February 9, 2018, the FWS announced the listing of the Texas Hornshell, a freshwater mussel species in areas including New Mexico and Texas where we operate in the Permian Basin, as an endangered species. In March 2018, we entered into a CCA concerning voluntary conservation actions with respect to the Texas Hornshell.

Participating in CCAs could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays, or limitations may be significant. Listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations ("NGOs") work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The listing of the Mexican Long Nosed bat, whose habitat includes the Permian Basin where we operate, and the Dunes Sagebrush Lizard in the Permian Basin, are examples of the NGOs' influence on ESA listing decisions.

On December 1 2020, the FWS announced the petitioning of the Peppered Chub to be listed as endangered or threatened under the ESA. The Peppered Chub is a freshwater fish that historically was found in the South Canadian, Cimarron, and Arkansas rivers within New Mexico, Texas, Oklahoma, and Kansas. Cimarex has operations near the South Canadian river in Oklahoma that could be impacted if the Peppered Chub is either listed as threatened or endangered under the ESA or if the FWS declares the basins of the South Canadian river to be critical habitat. The increase in endangered species listings, such as the Peppered Chub, may limit our ability to explore for or produce oil and gas in certain areas and increase our costs.

We have been an early entrant into new or emerging resource plays. As a result, our drilling results in these areas are uncertain. The value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

New or emerging oil and gas resource plays have limited or no production history. Consequently, in those new areas it is difficult to predict our future drilling costs and results, so our drilling, completing, and operating costs may be higher than initially expected and our production may be lower than initially expected. The value of our undeveloped acreage also may decline if our results are unsuccessful, and, as a result, we may have to impair the carrying value of our undeveloped acreage.

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

Many of our properties are in areas that may have been partially depleted or drained by earlier offset drilling. We have no control over offsetting operators, who could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the wellbore causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores), which could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. The possibility for these impacts may increase with respect to wells that we shut in as a response to lower commodity prices or the lack of pipeline and storage capacity such as occurred during the COVID-19 pandemic. In addition, completion operations and other activities conducted on other nearby wells could cause us, in order to protect our existing wells, to shut in production for indefinite periods of time. Shutting in our wells and damage to our wells from offset completions could result in increased costs and could adversely affect the reserves and re-commenced production from such shut in wells.

Our limited ability to influence operations and associated costs on non-operated properties could result in economic losses that are partially beyond our control.

For the year ended December 31, 2020, other companies operated approximately 12% of our net production. Our success in properties operated by others depends upon a number of factors outside of our control. These factors include timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology, and maintenance of safety and environmental standards. Our dependence on the operator and other working interest owners for these projects could prevent the realization of our targeted returns on capital in drilling or acquisition activities.

Our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.

The successful acquisition of properties requires an assessment of several factors, including:

- geological risks and recoverable reserves;
- future oil and gas prices and their appropriate market differentials;
- operating costs; and
- potential environmental risks and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Furthermore, the seller may be unwilling or unable, such as in a corporate acquisition like our acquisition of Resolute, to provide effective contractual protection against all or part of the identified problems.

On March 1, 2019, we completed the acquisition of Resolute. There can be no assurance that we will be able to successfully develop Resolute's assets or otherwise realize the expected benefits of the acquisition of Resolute. In addition, our business may be negatively impacted if Resolute has liabilities that were not disclosed.

We may lose leases if production is not established within the time periods specified in the leases or if we do not maintain production in paying quantities.

We could lose leases under certain circumstances if we do not maintain production in paying quantities or meet other lease requirements, and the amounts we spent for those leases could be lost. As we shut in wells in response to lower commodity prices or a lack of pipeline and storage capacity as a result of the COVID-19 pandemic, we may face claims that we are not complying with lease provisions. As noted above, the Biden administration also may impose new restrictions and regulations affecting our ability to drill, conduct hydraulic fracturing operations, and obtain necessary rights-of-way on federal lands, which could, in turn, result in the loss of federal leases. The combined net acreage expiring in the next three years represents approximately 3.1% of our total net undeveloped acreage at December 31, 2020. At that date, we had leases representing 132,051 net acres expiring in 2021, 35,516 net acres expiring in 2022, and 7,154 net acres expiring in 2023. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

We regularly sell non-strategic assets in order to increase capital resources available for other strategic assets and to create organizational and operational efficiencies. We also occasionally sell interests in strategic assets for the purpose of accelerating the development of and increasing efficiencies in such strategic assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties, and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers at times retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. In addition, with respect to offshore assets, if purchasers declare bankruptcy, the United States Department of Interior may pursue former owners for decommissioning expenses, which can be substantial. See Note 8 to the Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Competition for experienced technical personnel may negatively impact our operations.

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to develop our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering, and operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading “Litigation” in Note 10 to the Consolidated Financial Statements included in Part II, Item 8 of this Form 10-K, is incorporated by reference in response to this item.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our $0.01 par value common stock trades on the New York Stock Exchange ("NYSE") under the symbol XEC. A cash dividend was paid to our common stockholders in each quarter of 2020. Future dividend payments will depend on the company's level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

The closing price of Cimarex stock as reported on the NYSE on January 29, 2021, was $42.18. At January 31, 2021, Cimarex's 102,807,656 shares of outstanding common stock were held by approximately 1,174 stockholders of record.

Issuer Purchases of Equity Securities

The following table sets forth information regarding repurchases of our common stock during the year ended December 31, 2020. The shares repurchased represent shares of our common stock that employees elected to surrender to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Cimarex does not consider this a share buyback program.

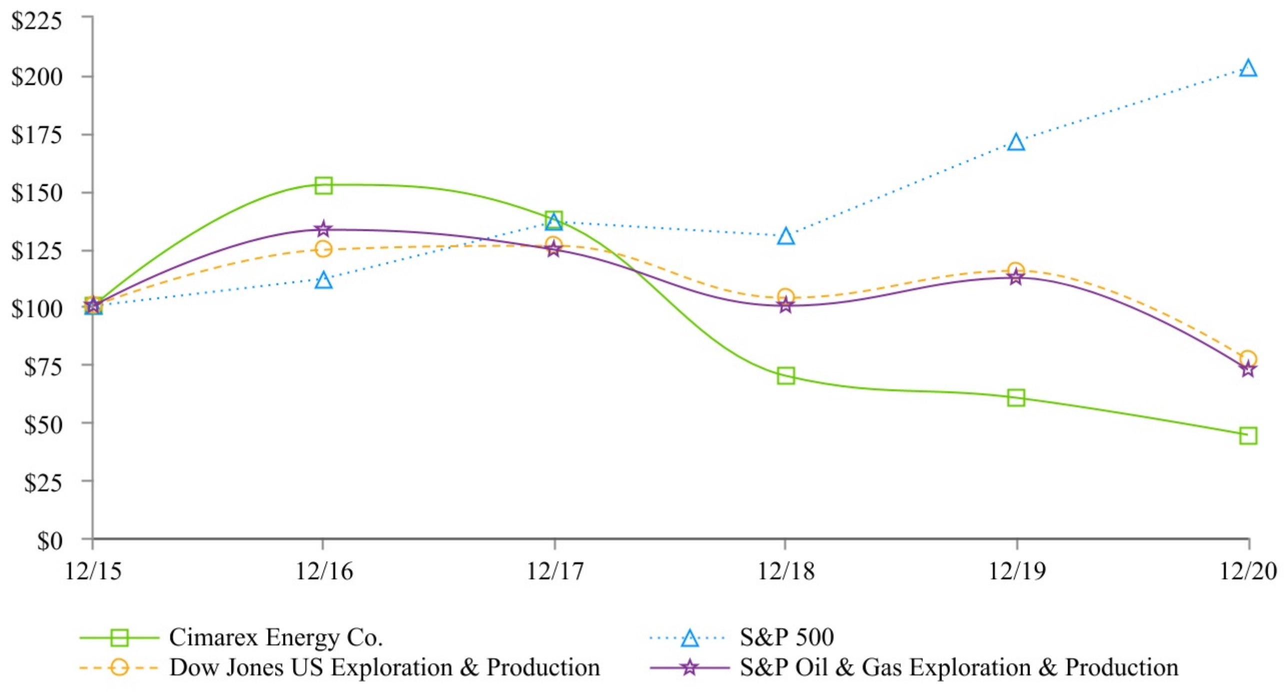
Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
January 1-31, 2020	—	$ —	—	—
February 1-29, 2020	—	—	—	—
March 1-31, 2020	12,199	13.56	—	—
April 1-30, 2020	1,160	20.53	—	—
May 1-31, 2020	—	—	—	—
June 1-30, 2020	—	—	—	—
July 1-31, 2020	94,245	24.57	—	—
August 1-31, 2020	—	—	—	—
September 1-30, 2020	—	—	—	—
October 1-31, 2020	—	—	—	—
November 1-30, 2020	1,468	31.25	—	—
December 1-31, 2020	52,620	36.21	—	—
Total	161,692	$ 26.73	—	—

Stock Performance Graph

The following graph shows the cumulative five-year total return on Cimarex Energy Co.’s common stock relative to the cumulative total returns of the S&P 500 index, the Dow Jones US Exploration & Production index, and the S&P Oil & Gas Exploration & Production index. The graph tracks the performance of a $100 investment in our common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2015 to December 31, 2020. The stock price performance included in this graph is not necessarily indicative of future stock price performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN*

Among Cimarex Energy Co., the S&P 500 Index,
the Dow Jones US Exploration & Production Index, and the S&P Oil & Gas Exploration & Production Index



* $100 invested on 12/31/15 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

A tabular presentation of the data in the above graph is provided below.

	2015	2016	2017	2018	2019	2020
Cimarex Energy Co.	$ 100.00	$ 152.64	$ 137.42	$ 69.88	$ 60.39	$ 44.43
S&P 500	$ 100.00	$ 111.96	$ 136.40	$ 130.42	$ 171.49	$ 203.04
Dow Jones US Exploration & Production	$ 100.00	$ 124.48	$ 126.10	$ 103.69	$ 115.51	$ 76.64
S&P Oil & Gas Exploration & Production	$ 100.00	$ 132.86	$ 124.48	$ 100.20	$ 112.25	$ 72.49

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with the Consolidated Financial Statements and accompanying notes thereto provided in Item 8 of this report.

	Years Ended December 31,				
	2020	2019	2018	2017	2016
	(in thousands, except per share amounts)				
Operating results:					
Oil, gas, and NGL sales	$ 1,512,688	$ 2,321,921	$ 2,297,645	$ 1,874,003	$ 1,221,218
Total revenues (1)	$ 1,558,595	$ 2,362,969	$ 2,339,017	$ 1,918,249	$ 1,257,345
Net (loss) income (2)	$ (1,967,458)	$ (124,619)	$ 791,851	$ 494,329	$ (408,803)
Earnings (loss) per common share:					
Basic	$ (19.73)	$ (1.33)	$ 8.32	$ 5.19	$ (4.38)
Diluted	$ (19.73)	$ (1.33)	$ 8.32	$ 5.19	$ (4.38)
Cash dividends declared per common share	$ 0.88	$ 0.80	$ 0.68	$ 0.32	$ 0.32
Cash flow data:					
Net cash provided by operating activities	$ 904,167	$ 1,343,966	$ 1,550,994	$ 1,096,564	$ 625,849
Net cash used by investing activities	$ (578,875)	$ (1,577,882)	$ (1,085,618)	$ (1,265,897)	$ (692,410)
Net cash used by financing activities	$ (146,869)	$ (472,028)	$ (65,244)	$ (83,009)	$ (59,945)

	December 31,				
	2020	2019	2018	2017	2016
	(in thousands, except proved reserves amounts)				
Balance sheet data:					
Cash and cash equivalents (3)	$ 273,145	$ 94,722	$ 800,666	$ 400,534	$ 652,876
Oil and gas properties, net (2) (3)	$ 3,436,669	$ 5,210,698	$ 3,715,330	$ 3,241,530	$ 2,354,267
Goodwill (3)	$ —	$ 716,865	$ 620,232	$ 620,232	$ 620,232
Total assets (2) (3)	$ 4,621,989	$ 7,140,029	$ 6,062,084	$ 5,042,639	$ 4,237,724
Deferred income tax (asset) liability	$ (20,472)	$ 338,424	$ 334,473	$ 101,618	$ (55,835)
Long-term obligations:					
Long-term debt (principal) (4)	$ 2,000,000	$ 2,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
Operating and finance leases (5)	$ 154,436	$ 202,921	$ —	$ —	$ —
Other	$ 229,794	$ 197,056	$ 200,564	$ 206,249	$ 184,444
Redeemable preferred stock (3)	$ 36,781	$ 81,620	$ —	$ —	$ —
Stockholders' equity (2)	$ 1,553,454	$ 3,576,141	$ 3,329,786	$ 2,568,278	$ 2,042,989
Proved Reserves:					
Oil (MBbls)	144,063	169,770	146,538	137,238	105,878
Gas (Bcf)	1,363	1,532	1,591	1,608	1,471
NGL (MBbls)	159,818	194,468	179,436	153,860	130,633
Total (MBOE)	531,021	619,595	591,195	559,037	481,748

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(1) Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, *Revenue from Contracts with Customers* ("ASC 606"), utilizing the modified retrospective approach. Because we utilized the modified retrospective approach, there was no impact to prior periods' reported amounts. Application of ASC 606 has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating in the Consolidated Statements of Operations and Comprehensive Income (Loss) under prior accounting standards are now reflected as deductions from revenue.

(2) During 2020, 2019, and 2016, we recorded non-cash full cost ceiling test impairments of our oil and gas properties totaling $1.64 billion, $618.7 million, and $757.7 million, respectively.

(3) We acquired Resolute Energy Corporation on March 1, 2019. Consideration for this acquisition included $284.4 million in cash, net of cash acquired, and $81.6 million in preferred stock. The final purchase price allocation included $1.72 billion to oil and gas properties and $94.2 million to goodwill. We concluded that goodwill was fully impaired at March 31, 2020 and recorded a $714.4 million impairment at that time. During 2020, we repurchased some of the preferred stock. See Notes 1, 2, and 13 to the Consolidated Financial Statements for further information regarding goodwill, the preferred stock, and the acquisition.

(4) On March 8, 2019, we issued $500.0 million aggregate principal amount of 4.375% senior unsecured notes due March 15, 2029 at 99.862% of par to yield 4.392% per annum. See Note 3 to the Consolidated Financial Statements for further information regarding our debt.

(5) Effective January 1, 2019, we began accounting for leases in accordance with Accounting Standards Update 2016-02, *Leases* ("Topic 842"), which requires lessees to recognize lease liabilities and right-of-use assets on the balance sheet for contracts that provide lessees with the right to control the use of identified assets for periods of greater than 12 months. Prior to January 1, 2019, we accounted for leases in accordance with ASC Topic 840, *Leases*, under which operating leases were not recorded on the balance sheet. See Note 10 to the Consolidated Financial Statements for further information regarding our leases and their financial statement impacts.

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements included in Item 8 of this report and also with **RISK FACTORS** in Item 1A of this report. This discussion also includes forward-looking statements. Refer to **CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS** in Part I of this report for important information about these types of statements. Discussion and analysis regarding 2020 and 2019 is provided below. For discussion and analysis regarding 2018, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2019 as previously filed with the SEC.

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are located entirely within the United States of America, mainly in Texas, New Mexico, and Oklahoma. Currently our operations are focused in two main areas: the Permian Basin and the Mid-Continent. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region consists of Oklahoma and the Texas Panhandle.

Our principal business objective is to increase shareholder value through the profitable growth of our proved reserves and production while seeking to minimize our impact on the communities in which we operate for the long-term. Our strategy centers on maximizing cash flow from producing properties for reinvestment in exploration and development activities and for providing cash returns to shareholders through dividends and debt reduction. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-strategic assets.

On March 1, 2019, we completed the acquisition of Resolute Energy Corporation ("Resolute"), an independent oil and gas company focused on the acquisition and development of unconventional oil and gas properties in the Delaware Basin area of the Permian Basin of west Texas. See Note 13 to the Consolidated Financial Statements for more information on the acquisition.

We believe that detailed technical analysis, operational focus, and a disciplined capital investment process mitigate risk and position us to continue to achieve profitable increases in proved reserves and production. Our drilling inventory and limited long-term commitments provide the flexibility to respond quickly to industry volatility. Our investments are generally funded with cash flow provided by operating activities together with cash on hand, bank borrowings, sales of non-strategic assets, and, from time to time, public financing based on our monitoring of capital markets and our balance sheet.

In the first quarter of 2020, the highly transmissible and pathogenic coronavirus known as severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) that causes the disease known as COVID-19 began to spread globally. In February 2020, we created a multi-disciplinary task force to address the potential impacts of COVID-19 on our employees and operations. The task force developed health and safety protocols to protect employees and augmented our business interruption plans to address potential impacts on our business from COVID-19.

Market Conditions

The oil and gas industry is cyclical and commodity prices can fluctuate significantly. We expect this volatility to persist. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, inventory storage levels, weather conditions, and other factors. Local market prices for oil and gas can be impacted by pipeline capacity constraints limiting takeaway and increasing basis differentials.

The reduction in economic activity from the COVID-19 pandemic resulted in unprecedented demand destruction and inventory increases for oil and natural gas liquids. In addition, in early March 2020, members of the Organization of the Petroleum Exporting Countries ("OPEC") and other countries failed to reach an agreement on oil production limits and Saudi Arabia unilaterally reduced the sales price of its oil and announced that it would increase its oil production. As a result of these actions and the COVID-19 pandemic, WTI oil prices dropped from an average of $57.53 per barrel in January 2020 to $16.70 per barrel in April 2020. Since April 2020, average WTI oil prices have risen to $47.07 per barrel in December 2020. The oil price improvement and or stabilization has coincided with some recovery of global economic activity, lower supply from major oil producing countries, and moderating inventory levels.

In response to the decline in oil prices in the second quarter 2020, we took immediate steps to reduce our capital investment, including releasing all but one drilling rig by mid-May and deferring well completion activity. This resulted in a reduction in exploration, development, and acquisition capital expenditures from $255.9 million in the first quarter of 2020 to $83.8 million in the second quarter of 2020, $80.5 million in the third quarter of 2020, and $136.5 million in the fourth quarter of 2020. As a result, total exploration, development, and acquisition capital expenditures for 2020 were $556.7 million. This level of capital expenditures was less than our cash flow from operating activities, which has allowed us to build our cash balance and not incur any incremental borrowings this year. With the subsequent improvement in oil prices, we exited 2020 running five drilling rigs and completing wells with one completion crew.

The table below presents average NYMEX prices and our company-wide average realized prices and basis differentials for 2020 and 2019. The average NYMEX and realized prices have declined for all products, while the average basis differentials have improved.

	Years Ended December 31,		Variance Between 2020 / 2019
	2020	2019	
Average NYMEX price			
Oil — per barrel	$ 39.40	$ 57.03	(31)%
Gas — per Mcf	$ 2.08	$ 2.63	(21)%
Average realized price			
Oil — per barrel	$ 35.59	$ 52.77	(33)%
Gas — per Mcf	$ 1.05	$ 1.11	(5)%
NGL — per barrel	$ 10.53	$ 13.55	(22)%
Average price differential			
Oil — per barrel	$ (3.81)	$ (4.26)	11%
Gas — per Mcf	$ (1.03)	$ (1.52)	32%

The average price differentials that we realized in our two primary areas of operation are shown in the table below for the periods indicated.

	Average Price Differentials				
	Year	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2020					
Oil					
Permian Basin	$ (3.74)	$ (2.79)	$ (2.71)	$ (8.12)	$ (2.00)
Mid-Continent	$ (4.43)	$ (0.99)	$ (5.06)	$ (9.53)	$ (2.02)
Total Company	$ (3.81)	$ (2.57)	$ (2.99)	$ (8.28)	$ (1.99)
Gas					
Permian Basin	$ (1.39)	$ (1.34)	$ (1.15)	$ (1.09)	$ (1.85)
Mid-Continent	$ (0.41)	$ (0.36)	$ (0.31)	$ (0.31)	$ (0.57)
Total Company	$ (1.03)	$ (0.98)	$ (0.84)	$ (0.80)	$ (1.40)
2019					
Oil					
Permian Basin	$ (4.48)	$ (2.18)	$ (3.76)	$ (5.80)	$ (6.90)
Mid-Continent	$ (3.14)	$ (2.05)	$ (3.72)	$ (4.39)	$ (2.17)
Total Company	$ (4.26)	$ (2.16)	$ (3.74)	$ (5.58)	$ (6.03)
Gas					
Permian Basin	$ (2.14)	$ (1.67)	$ (1.83)	$ (3.10)	$ (1.91)
Mid-Continent	$ (0.68)	$ (0.74)	$ (0.66)	$ (0.86)	$ (0.46)
Total Company	$ (1.52)	$ (1.31)	$ (1.35)	$ (2.14)	$ (1.24)

Pipeline expansion projects in the Permian Basin and reduced drilling activity and production have eased take away constraints and improved price differentials. However, if pipeline projects are delayed, production increases faster than capacity increases, or the basin experiences pipeline disruptions or other constraints, differentials could potentially worsen. Our revenue, profitability, and future growth are highly dependent on the prices we receive for our oil and gas production and can be adversely affected by realized price decreases.

Summary of Operating and Financial Results for the year ended December 31, 2020 as compared to the year ended December 31, 2019

- Total daily production volumes decreased 9% to 252.5 MBOE per day.
- Oil volumes decreased 11% to 76.7 MBbls per day.
- Gas volumes decreased 8% to 635.6 MMcf per day.
- NGL volumes decreased 10% to 69.8 MBbls per day.
- Total production revenue decreased 35% to $1.51 billion.
- Year-end proved reserves decreased 14% to 531.0 MMBOE, as compared to 619.6 MMBOE at year-end 2019.
- Exploration and development capital investments were $544.9 million, as compared to $1.24 billion in 2019.
- Cash flow provided by operating activities decreased 33% to $904.2 million.
- Net loss of $1.97 billion ($19.73 per diluted share) as compared to a net loss of $124.6 million ($1.33 per diluted share) in 2019.

All of the above results were impacted by the demand destruction and lower prices in 2020 that occurred primarily due to the COVID-19 pandemic. Further discussion of these results is provided below.

Proved Reserves

Our proved reserves by region at December 31, 2020 and 2019 were as follows:

	December 31, 2020			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
Permian Basin	790,750	126,327	103,606	361,725
Mid-Continent	570,578	17,491	56,130	168,717
Other	1,514	245	82	579
	1,362,842	144,063	159,818	531,021

	December 31, 2019			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
Permian Basin	870,208	147,662	130,007	422,703
Mid-Continent	660,161	21,848	64,377	196,252
Other	1,776	260	84	640
	1,532,145	169,770	194,468	619,595

Year-end 2020 proved reserves decreased approximately 14% to 531.0 MMBOE, compared to 619.6 MMBOE at year-end 2019. At December 31, 2020, proved gas reserves were 1.36 Tcf, proved oil reserves were 144.1 MMBbls, and proved NGL reserves were 159.8 MMBbls. Reserves in the Permian Basin accounted for 68% of our total proved reserves with nearly all of the remainder in our Mid-Continent region. See **SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)** in Item 8 for a more detailed discussion regarding year-over-year changes in our proved reserves.

The process of estimating quantities of oil, gas, and NGL reserves is complex. Judgment and interpretation are required in the evaluation of all available geological, geophysical, engineering, and economic data. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. See ***Proved Reserves Estimation Procedures*** in Items 1 and 2 for a discussion of our reserve estimation process and Item 1A **RISK FACTORS**, which includes a discussion of factors that affect our proved reserves estimates.

RESULTS OF OPERATIONS

Revenues

Our revenues are derived from sales of our oil, gas, and NGL production. Increases or decreases in our revenues, profitability, and future production growth are highly dependent on the commodity prices we receive. Prices are market driven and we expect that future prices will continue to fluctuate due to supply and demand factors, availability of transportation, seasonality, and geopolitical, economic, and other factors.

Production volumes and realized prices were lower for all products during the year ended December 31, 2020 as compared to the year ended December 31, 2019. Subsequent to the first quarter of 2020, we reduced our drilling and completion activities and curtailed or shut in production in certain areas as a result of the unprecedented demand destruction and resulting severe price decreases for oil stemming from the COVID-19 pandemic. Prices improved in the latter part of the year. The following table shows our production revenues by product for 2020 and 2019 as well as the change in revenues due to changes in prices and volumes.

Production Revenue (in thousands)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019		Price / Volume Variance: Price	Volume	Total
Oil sales	$ 999,682	$ 1,660,210	$ (660,528)	(40)%	$ (482,534)	$ (177,994)	$ (660,528)
Gas sales	243,932	278,776	(34,844)	(12)%	(13,958)	(20,886)	(34,844)
NGL sales	269,074	382,935	(113,861)	(30)%	(77,172)	(36,689)	(113,861)
	$ 1,512,688	$ 2,321,921	$ (809,233)	(35)%	$ (573,664)	$ (235,569)	$ (809,233)

The table below presents our production volumes by commodity, our average realized commodity prices, and certain major U.S. index prices. The sale of our Permian Basin oil production is typically tied to the WTI Midland benchmark price and the sale of our Mid-Continent oil production is typically tied to the WTI Cushing benchmark price. During 2020 and 2019, 88% and 84%, respectively, of our oil production was in the Permian Basin. Our realized prices do not include settlements of commodity derivative contracts.

	Years Ended December 31,		Variance Between 2020 / 2019	
	2020	2019		
Oil				
Total volume — MBbls	28,087	31,463	(3,376)	(11)%
Total volume — MBbls per day	76.7	86.2	(9.5)	(11)%
Percentage of total production	30 %	31 %		
Average realized price — per barrel	$ 35.59	$ 52.77	$ (17.18)	(33)%
Average WTI Midland price — per barrel	$ 39.71	$ 55.53	$ (15.82)	(28)%
Average WTI Cushing price — per barrel	$ 39.40	$ 57.03	$ (17.63)	(31)%
Gas				
Total volume — MMcf	232,625	251,567	(18,942)	(8)%
Total volume — MMcf per day	635.6	689.2	(53.6)	(8)%
Percentage of total production	42 %	41 %		
Average realized price — per Mcf	$ 1.05	$ 1.11	$ (0.06)	(5)%
Average Henry Hub price — per Mcf	$ 2.08	$ 2.63	$ (0.55)	(21)%
NGL				
Total volume — MBbls	25,554	28,254	(2,700)	(10)%
Total volume — MBbls per day	69.8	77.4	(7.6)	(10)%
Percentage of total production	28 %	28 %		
Average realized price — per barrel	$ 10.53	$ 13.55	$ (3.02)	(22)%
Total				
Total production — MBOE	92,412	101,645	(9,233)	(9)%
Total production — MBOE per day	252.5	278.5	(26.0)	(9)%
Average realized price — per BOE	$ 16.37	$ 22.84	$ (6.47)	(28)%

Our 2020 daily production volumes were 252.5 MBOE, a 9% decrease from 2019. This decrease is the result of our intentional reduction in capital spending and curtailing and shutting in production in certain areas due to the demand destruction caused primarily by the COVID-19 pandemic. See ***Production Volumes, Prices, and Costs*** and ***Exploration and Development Overview*** in Items 1 and 2 of this report for production information by region and a discussion of our drilling activities.

Other Revenues

Gas gathering and other is revenue earned when we transport, process, and market some third-party gas that is associated with our equity gas. Gas marketing is comprised of the fees we earn when we act as agent under short-term sales and supply agreements and market and sell gas for other working interest owners, net of the related expenses. Gas marketing also includes net pipeline settlements incurred as a result of these activities. The table below reflects revenues from third-party gas gathering and other and our net marketing margin for marketing other working interest owners' gas for the periods indicated.

Gas Gathering and Marketing Revenues (in thousands)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019
Gas gathering and other	$ 47,842	$ 42,454	$ 5,388
Gas marketing	$ (1,935)	$ (1,406)	$ (529)

Fluctuations in revenues from gas gathering and gas marketing activities are primarily a function of increases and decreases in volumes, commodity prices, and gathering rate charges.

Operating Costs and Expenses

Costs associated with producing oil and gas are substantial. Among other factors, some of these costs vary with commodity prices, some trend with the volume of production, some are a function of the number of wells we own, some depend on the prices charged by service companies, and some fluctuate based on a combination of the foregoing.

Total operating costs and expenses of $3.84 billion in 2020 were 55% higher than the $2.48 billion incurred in 2019. The primary reasons for the increase were: (i) the $1.64 billion in ceiling test impairments incurred in 2020, which was $1.02 billion greater than the ceiling test impairment incurred in 2019 and (ii) the $714.4 million impairment of goodwill incurred during 2020, partially offset by (iii) the $186.2 million decrease in depreciation, depletion, and amortization in 2020. The following table shows our operating costs and expenses for the years indicated and a discussion of the operating costs and expenses follows.

Operating Costs and Expenses (in thousands, except per BOE)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019	Per BOE 2020	Per BOE 2019
Impairment of oil and gas properties	$ 1,638,329	$ 618,693	$ 1,019,636	N/A	N/A
Depreciation, depletion, and amortization	695,954	882,173	(186,219)	$ 7.53	$ 8.68
Asset retirement obligation	14,653	8,586	6,067	$ 0.16	$ 0.08
Impairment of goodwill	714,447	—	714,447	N/A	N/A
Production	285,324	339,941	(54,617)	$ 3.09	$ 3.34
Transportation, processing, and other operating	213,366	238,259	(24,893)	$ 2.31	$ 2.34
Gas gathering and other	23,591	23,294	297	$ 0.26	$ 0.23
Taxes other than income	79,699	148,953	(69,254)	$ 0.86	$ 1.47
General and administrative	111,005	95,843	15,162	$ 1.20	$ 0.94
Stock-based compensation	29,895	26,398	3,497	$ 0.32	$ 0.26
Loss on derivative instruments, net	35,534	76,850	(41,316)	N/A	N/A
Other operating expense, net	839	19,305	(18,466)	N/A	N/A
	$ 3,842,636	$ 2,478,295	$ 1,364,341		

Impairment of Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. Under this method, we are required to perform quarterly ceiling test calculations to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling test impairment. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

During 2020, we recognized ceiling test impairments totaling $1.64 billion. The impairments resulted primarily from the impact of decreases in the 12-month average trailing prices for oil, gas, and NGLs as well as significant basis differentials utilized in determining the estimated future net cash flows from proved reserves. We may recognize additional ceiling test impairments in the future.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization (“DD&A”) consisted of the following for the periods indicated:

DD&A Expense (in thousands, except per BOE)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019	Per BOE 2020	Per BOE 2019
Depletion	$ 625,481	$ 817,099	$ (191,618)	$ 6.77	$ 8.04
Depreciation	70,473	65,074	5,399	0.76	0.64
	$ 695,954	$ 882,173	$ (186,219)	$ 7.53	$ 8.68

Depletion of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed realized sales price for future production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our depletion expense. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, reclassifications of properties from unproved to proved, and impairments of oil and gas properties will also impact depletion expense. Our depletion expense decreased during 2020 as compared to 2019 primarily due to a decrease in our depletable basis mostly resulting from ceiling test impairments recognized at December 31, 2019, March 31, 2020, June 30, 2020, and September 30, 2020. In addition, our depletion expense decreased as a result of a decrease in our production resulting from a reduction in drilling and completion activity subsequent to the first quarter 2020 and curtailment or shut in of production in certain areas stemming from the demand destruction caused by the COVID-19 pandemic. These causes for decreased depletion expense were partially offset by a decrease in our reserves, primarily due to a decrease in the trailing twelve month prices used to calculate reserves, which increased depletion expense.

Fixed assets consist primarily of gas gathering and plant facilities, water infrastructure, vehicles, airplanes, office furniture, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from 3 to 30 years. Also included in our depreciation expense is the depreciation of the right-of-use asset associated with our finance lease gathering system. The increase in depreciation expense during 2020 as compared to 2019 is primarily due to increased depreciation on our gathering and plant facilities due to ongoing expenditures on this infrastructure and projects being placed into service.

Asset Retirement Obligation

Asset retirement obligation expense is typically primarily comprised of accretion expense. In periods subsequent to the initial measurement of an asset retirement obligation liability at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. Also included in asset retirement obligation expense are gains and losses recognized on the settlement of asset retirement obligation liabilities. Accretion expense for the year ended December 31, 2020, also included $4.9 million to increase our estimated asset retirement obligation liability to decommission certain offshore properties in the Gulf of Mexico in which we were a prior lessee. As a result of the current lessee defaulting on its obligation to decommission the properties, in 2018 the Bureau of Safety and Environmental Enforcement ordered us and other prior lessees to decommission all wells, pipelines, platforms, and facilities related to the properties.

Impairment of Goodwill

We concluded that goodwill was impaired at March 31, 2020 and expensed the entire balance of $714.4 million at that time. See Note 1 to the Consolidated Financial Statements for additional information regarding the impairment of goodwill.

Production

Production expense generally consists of costs for labor, equipment, maintenance, saltwater disposal, compression, power, treating, and miscellaneous other costs (lease operating expense). Production expense also includes well workover activity necessary to maintain production from existing wells. Production expense consisted of lease operating expense and workover expense as follows:

	Years Ended December 31,		Variance Between	Per BOE	
Production Expense (in thousands, except per BOE)	**2020**	**2019**	**2020 / 2019**	**2020**	**2019**
Lease operating expense	$ 244,397	$ 273,092	$ (28,695)	$ 2.65	$ 2.68
Workover expense	40,927	66,849	(25,922)	0.44	0.66
	$ 285,324	$ 339,941	$ (54,617)	$ 3.09	$ 3.34

Lease operating expense decreased 11%, or $28.7 million, in 2020 compared to 2019. The decrease is primarily related to the reduction in activity and our cost saving efforts such as our initiative to reduce the use of outside labor, our voluntary early retirement incentive program and involuntary reduction in workforce, delaying non-essential work, shutting in wells, and decreasing drilling and completion, which has led to fewer wells coming online.

Workover expense decreased 39%, or $25.9 million, during 2020 as compared to 2019. We had fewer workover projects during 2020 as compared to 2019 as a result of a concerted effort to reduce activity and delay non-essential work.

Transportation, Processing, and Other Operating

Transportation, processing, and other operating costs principally consist of expenditures to prepare and transport production from the wellhead, including gathering, fuel, compression, and processing costs. Costs vary by region and will fluctuate with increases or decreases in production volumes, contractual fees, and changes in fuel and compression costs, and the structure of sales contracts. If the sales contract transfers control of the product at the wellhead, transportation and processing costs are included as a reduction in the revenue we record and are not included in transportation, processing, and other operating costs. Transportation, processing, and other operating costs in 2020 were 10%, or $24.9 million, lower than in 2019 primarily due to a decrease in production volumes.

Gas Gathering and Other

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs and operating and maintenance expenses. A portion of these costs are reclassified to Transportation, processing, and other expense and Production expense in order to reflect an allocation of the costs incurred to operate our gas gathering facilities as a cost of transporting our equity share of gas produced and operating our wells. Gas gathering and other in 2020 was minimally higher than in 2019.

Taxes Other than Income

Taxes other than income consist of production (or severance) taxes, ad valorem taxes, and other taxes. State and local taxing authorities assess these taxes, with production taxes being based on the volume or value of production and ad valorem taxes being based on the value of properties. The following table presents taxes other than income for the years indicated.

Taxes Other than Income (in thousands)	**Years Ended December 31,** 2020	2019	**Variance Between 2020 / 2019**
Production	$ 64,075	$ 111,819	$ (47,744)
Ad valorem	14,500	36,291	(21,791)
Other	1,124	843	281
	$ 79,699	$ 148,953	$ (69,254)
Taxes other than income as a percentage of production revenue	5.3 %	6.4 %	

Taxes other than income decreased 46%, or $69.3 million, in 2020 as compared to 2019. Production taxes make up the majority of our taxes other than income and they decreased primarily due to decreases in oil and NGL prices. Ad valorem taxes also decreased primarily due to decreased valuations based on decreased commodity prices. Other taxes other than income are comprised of franchise and consumer use and sales taxes.

General and Administrative

General and administrative ("G&A") expense consists primarily of salaries and related benefits, office rent, legal and consulting fees, systems costs, and other administrative costs incurred. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting. The amount of expense capitalized varies and depends on whether the cost incurred can be directly identified with acquisition, exploration, and development activities. The percentage of gross G&A capitalized was 34% and 44% during 2020 and 2019, respectively. In response to low oil prices and demand destruction in 2020, we reduced our acquisition, exploration, and development activities and, therefore, the percentage of gross G&A capitalized decreased from 2019. The table below shows our G&A costs.

General and Administrative Expense (in thousands)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019
Gross G&A	$ 168,815	$ 170,757	$ (1,942)
Less amounts capitalized to oil and gas properties	(57,810)	(74,914)	17,104
G&A expense	$ 111,005	$ 95,843	$ 15,162

G&A expense increased 16%, or $15.2 million, in 2020 as compared to 2019. This increase is primarily due to $28.7 million in severance expense, none of which was capitalized, associated with the voluntary early retirement incentive program that we offered to employees who met certain eligibility criteria in the first quarter of 2020 and the involuntary reduction in workforce program that we carried out in the third quarter of 2020. These programs reduced our headcount by approximately 24% from December 31, 2019 and we expect G&A expense related to salaries and wages to be lower in future periods as a result. The increase in G&A expense due to the severance expense was partially offset by decreases in salaries and wages, health insurance, annual bonus, consulting, and travel expenses.

Stock-based Compensation

Stock-based compensation expense consists of charges resulting from the amortization of the cost of restricted stock and stock option awards, net of amounts capitalized to oil and gas properties. We have recognized stock-based compensation cost as follows:

Stock-based Compensation Expense (in thousands)	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance Between 2020 / 2019
Restricted stock awards:			
Performance stock awards	$ 17,338	$ 21,590	$ (4,252)
Service-based stock awards	26,014	25,611	403
	43,352	47,201	(3,849)
Stock option awards	1,460	1,903	(443)
Total stock-based compensation cost	44,812	49,104	(4,292)
Less amounts capitalized to oil and gas properties	(14,917)	(22,706)	7,789
Stock-based compensation expense	$ 29,895	$ 26,398	$ 3,497

Periodic stock-based compensation expense will fluctuate based on the grant date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. Our accounting policy is to account for forfeitures in compensation cost when they occur. The amount capitalized to oil and gas properties decreased as a percentage of total stock-based compensation cost in 2020 as compared to 2019 due to reduced acquisition, exploration, and development activities in 2020 as a result of the low oil prices and demand destruction experienced in 2020 stemming from the COVID-19 pandemic and OPEC and other countries' actions. The decreased capitalization caused the overall stock-based compensation expense to increase.

Loss on Derivative Instruments, Net

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly cash settlements (if any) of the instruments. We have elected not to designate our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to our derivative instruments. Consequently, changes in the fair value of our derivative instruments and cash settlements on the instruments are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows. The following table presents the components of "Loss on derivative instruments, net" for the years indicated. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

Loss on Derivative Instruments, Net (in thousands)	Years Ended December 31, 2020	2019	Variance Between 2020 / 2019
Decrease (increase) in fair value of derivative instruments, net:			
Gas contracts	$ 56,475	$ (13,114)	$ 69,589
Oil contracts	98,306	76,833	21,473
	154,781	63,719	91,062
Cash (receipts) payments on derivative instruments, net:			
Gas contracts	(15,476)	(40,114)	24,638
Oil contracts	(103,771)	53,245	(157,016)
	(119,247)	13,131	(132,378)
Loss on derivative instruments, net	$ 35,534	$ 76,850	$ (41,316)

Other Operating Expense, Net

Other operating expense, net decreased $18.5 million in 2020 as compared to 2019. This expense is typically comprised primarily of litigation settlements and allowance for credit losses adjustments. Other operating expense, net in 2019 included $10.0 million in litigation settlements and $8.4 million in acquisition-related costs incurred to effect the Resolute acquisition. The acquisition-related costs consisted primarily of advisory and legal fees.

Other Income and Expense

Other Income and Expense (in thousands)	Years Ended December 31, 2020	2019	Variance Between 2020 / 2019
Interest expense	$ 92,914	$ 93,386	$ (472)
Capitalized interest	(50,030)	(56,232)	6,202
Loss on early extinguishment of debt	—	4,250	(4,250)
Other, net	(540)	(5,741)	5,201
	$ 42,344	$ 35,663	$ 6,681

The majority of our interest expense relates to interest on the borrowings under our senior unsecured notes, with such interest totaling $83.9 million and $79.9 million during 2020 and 2019, respectively. Also included in interest expense is interest expense on our Credit Facility borrowings, the amortization of debt issuance costs and discounts, interest expense on our finance lease, and miscellaneous interest expense. See **LIQUIDITY AND CAPITAL RESOURCES *Long-Term Debt*** below for further information regarding our debt. The $4.3 million loss on early extinguishment of debt incurred during 2019 was associated with the $600.0 million of 8.5% senior notes due May 1, 2020 that we acquired with Resolute on March 1, 2019 and elected to immediately repay.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells, and constructing midstream assets. Capitalized interest will fluctuate based primarily on the amount of costs subject to interest capitalization and based on the rates applicable to borrowings outstanding during the period. The amount of costs subject to interest capitalization was lower in 2020 as compared to 2019, primarily due to the decrease in the balance of non-producing leasehold costs as a result of transfers to proved properties as well as due to a decrease in the in-progress costs of drilling and completing wells and constructing midstream assets due to decreased activity in 2020.

Other, net includes interest income of $0.7 million and $3.3 million in 2020 and 2019, respectively. The decrease in interest income in 2020 is primarily due to the decrease in our investable cash balance after acquiring Resolute on March 1, 2019. Other components of Other, net include miscellaneous income and expense items that vary from period to period, including gain or loss related to the sale or value of oil and gas well equipment and supplies, gain or loss on miscellaneous fixed asset sales, and income and expense associated with other non-operating activities.

Income Tax Benefit

The components of our provision for income taxes and our combined federal and state effective income tax rates were as follows:

Income Tax Benefit (in thousands)	**Years Ended December 31, 2020**	**2019**	**Variance Between 2020 / 2019**
Current tax (benefit) expense	$ (31)	$ 532	$ (563)
Deferred tax benefit	(358,896)	(26,902)	(331,994)
	$ (358,927)	$ (26,370)	$ (332,557)
Combined federal and state effective income tax rate	15.4 %	17.5 %	

Our combined federal and state effective tax rates, as shown above, differ from the statutory rate primarily due to state income taxes, non-deductible expenses, changes in tax laws and tax rates enacted in the period, and changes in valuation allowances. See Note 9 to the Consolidated Financial Statements for further information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

With the volatility in commodity prices and recognizing the U.S. oil volume growth impact on the overall world oil supply and demand balance, we have adjusted our approach to our reinvestment rates to target 70 to 80% of operating cash flow. With this investment approach, we will have 20 to 30% of cash flow available to increase cash on our balance sheet, which we plan to initially target to reduce debt and continue to fund and increase our regular common stock cash dividend.

We strive to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include our cash flow from operations, cash on hand, available borrowing capacity under our revolving credit facility, and proceeds from sales of non-strategic assets.

Our liquidity is highly dependent on the prices we receive for the oil, gas, and NGLs we produce. The prices we receive are determined by prevailing market conditions and greatly influence our revenue, cash flow, profitability, access to capital, and future rate of growth. See **RESULTS OF OPERATIONS** ***Revenues*** above for further information regarding the impact realized prices have had on our 2020 earnings.

We address volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a balanced and abundant drilling inventory and limited long-term commitments, which enable us to respond quickly to industry volatility. In response to the decline in oil prices in the second quarter of 2020, we took immediate steps to reduce our capital investment, including releasing all but one drilling rig by mid-May 2020 and deferring well completion activity. As a result, total exploration, development, and acquisition capital expenditures for 2020 were $556.7 million. This level of capital expenditures was less than our cash flow from operating activities, which has allowed us to build our cash balance and not incur any incremental borrowings this year. With the subsequent improvement in oil prices, we exited 2020 running five drilling rigs and completing wells with one completion crew. See ***Capital Expenditures*** below for information regarding our 2020 capital expenditures and our projected 2021 expenditures.

We periodically use derivative instruments to mitigate volatility in commodity prices. At December 31, 2020, we had derivative contracts covering a portion of our 2021 and 2022 production. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels. See Note 4 to the Consolidated Financial Statements for information regarding our derivative instruments.

Cash and cash equivalents at December 31, 2020 were $273.1 million. At December 31, 2020, our long-term debt consisted of $2.0 billion of senior unsecured notes, with $750 million 4.375% notes due in 2024, $750 million 3.90% notes due in 2027, and $500 million 4.375% notes due in 2029. At December 31, 2020, we had no borrowings and $2.5 million in letters of credit outstanding under our credit facility, leaving an unused borrowing availability of $1.248 billion. See ***Long-Term Debt*** below for more information regarding our debt.

In December 2020, we paid $43.0 million to repurchase 55% of the outstanding shares of our preferred stock and we may, from time to time, seek to repurchase additional shares of our outstanding preferred stock through cash repurchases and/or exchanges for equity securities, privately negotiated transactions, or otherwise. Such activities, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, and other factors. See Note 2 to the Consolidated Financial Statements for information regarding our preferred stock.

We expect our operating cash flow and other capital resources to be adequate to meet our needs for planned capital expenditures, working capital, debt service, and dividends declared for the next twelve months.

Analysis of Cash Flow Changes

The following table presents the totals of the major cash flow classification categories from our Consolidated Statements of Cash Flows for the periods indicated.

	Years Ended December 31,	
(in thousands)	**2020**	**2019**
Net cash provided by operating activities	$ 904,167	$ 1,343,966
Net cash used by investing activities	$ (578,875)	$ (1,577,882)
Net cash used by financing activities	$ (146,869)	$ (472,028)

Net cash provided by operating activities in 2020 was $904.2 million, down $439.8 million, or 33%, from $1.34 billion in 2019. The decrease resulted primarily from a decrease in revenues due to the price collapses and demand destruction seen in 2020 as a result of the COVID-19 pandemic and actions of OPEC and other countries. This decrease was partially offset by: (i) increased cash inflows for settlements of derivative instruments, (ii) decreased overall operating expenses (e.g. production, taxes other than income, and transportation, processing, and other operating expenses) primarily as a result of decreased activity, production, and revenues, and (iii) a decreased investment in working capital. See **RESULTS OF OPERATIONS** above for more information regarding the changes in revenue and operating expenses.

Net cash used by investing activities was $578.9 million and $1.58 billion in 2020 and 2019, respectively. The majority of our cash flows used by investing activities are for oil and gas capital expenditures, which totaled $594.8 million and $1.25 billion in 2020 and 2019, respectively. Our 2020 oil and gas capital expenditures decreased as compared to 2019 due to deliberate actions taken by us to reduce our capital investment in response to the decline in oil prices and demand experienced in 2020. Net cash used by investing activities also includes net cash outflows for oil and gas property acquisitions, which were minimal in 2020 at $11.9 million, but in 2019 included the $325.7 million cash portion of the consideration paid for the Resolute acquisition, net of the $41.2 million in cash acquired with Resolute. Our other capital expenditures, which are primarily for midstream assets, were $44.3 million and $73.7 million in 2020 and 2019, respectively, with 2020 decreasing due to the overall decrease in capital investments in 2020. Included in net cash used by investing activities are proceeds from other asset sales, which are generally for the divestiture of non-strategic oil and gas properties and totaled $72.1 million and $30.0 million in 2020 and 2019, respectively. Proceeds from other asset sales in 2020 included net cash proceeds of $68.7 million from the sale of certain water infrastructure assets in Eddy County, New Mexico.

Net cash used by financing activities was $146.9 million and $472.0 million in 2020 and 2019, respectively. During 2020, we paid $43.0 million to repurchase some of our outstanding preferred stock. During 2020, we borrowed and repaid an aggregate of $172.0 million on our credit facility to meet cash requirements as needed. During 2020, we amended our credit facility, paying $1.5 million in financing costs. During 2019, we issued $500.0 million aggregate principal amount of 4.375% senior unsecured notes due March 15, 2029 at 99.862% of par for proceeds of $499.3 million, paying $4.6 million in underwriting fees and financing costs. Additionally in 2019, we borrowed and repaid an aggregate of $2.12 billion on our credit facility to assist in funding the Resolute acquisition and thereafter to meet cash requirements as needed. In connection with the acquisition of Resolute, we assumed $870.0 million in principal amount of long-term debt that we immediately repaid, incurring a redemption fee of $4.3 million. During 2019, we amended our credit facility, paying $3.0 million in financing costs. Net cash used by financing activities during both years included: (i) the payment of dividends, (ii) the payment of income tax withholdings made on behalf of our employees upon the net settlement of equity-classified stock awards, and (iii) finance lease payments. During 2020 and 2019, we declared cash dividends on both our common and preferred stock quarterly, paying them in the quarter following declaration. During 2020, we paid one $0.20 per share dividend and three $0.22 per share dividends on our common stock and four $20.3125 per share dividends on our preferred stock, totaling $93.0 million. During 2019, we paid one $0.18 per share dividend and three $0.20 per share dividends on our common stock and three $20.3125 per share dividends on our preferred stock, totaling $81.7 million. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors. We paid employee income tax withholdings on the net settlement of equity-classified stock awards totaling $4.5 million and $5.2 million in 2020 and 2019, respectively. We paid finance lease payments of $4.8 million and $3.9 million in 2020 and 2019, respectively.

Capital Expenditures

The following table presents capitalized expenditures for oil and gas property acquisition, exploration, and development activities.

(in thousands)	Years Ended December 31, 2020	2019
Acquisitions:		
Proved	$ 11,878	$ 695,450
Unproved	—	1,025,376
	11,878	1,720,826
Exploration and development:		
Land and seismic	48,468	60,175
Exploration and development	496,388	1,181,605
	544,856	1,241,780
Total acquisition, exploration, and development capital expenditures	$ 556,734	$ 2,962,606

Amounts in the table above are presented on an accrual basis. Oil and gas capital expenditures and acquisitions of oil and gas properties in the Consolidated Statements of Cash Flows reflect activities on a cash basis.

On March 1, 2019, we completed the acquisition of Resolute. The fair value of the proved and unproved properties recorded in the purchase price allocation for this acquisition was $1.72 billion.

Our 2020 total capital expenditures were originally forecast to range from $1.25-$1.35 billion, with the majority expected to be invested in the Permian Basin. In response to the decline in oil prices in the second quarter 2020, we took immediate steps to reduce our capital investment, including releasing all but one drilling rig by mid-May and deferring well completion activity. This resulted in total acquisition, exploration, and development capital expenditures for 2020 of $556.7 million. Approximately 92% of our 2020 exploration and development expenditures were in the Permian Basin and 8% were in the Mid-Continent. During 2020, we completed or participated in the completion of 149 gross (51.0 net) productive wells, of which we operated 61 gross (47.6 net) wells. With the subsequent improvement in oil prices, we exited 2020 running five drilling rigs and completing wells with one completion crew. See Items 1 and 2 of this report for further information regarding our oil and gas properties.

In 2020, the level of our capital expenditures was less than our cash flow from operating activities, which allowed us to build our cash balance and not incur any incremental borrowings. We intend to fund our 2021 capital investment program with cash flow from operating activities and potential sales of non-strategic assets. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may cause us to borrow and repay funds under our credit facility from time-to-time. Based on current economic conditions, our 2021 total capital expenditures are projected to range from $650 million to $750 million. This includes drilling and completion capital of approximately $500 million to $600 million, investments in saltwater disposal/midstream infrastructure of approximately $40 million, and investments in other, including capitalized G&A and non-producing leasehold, of approximately $110 million. Over 90% of our planned 2021 drilling and completion capital is expected to be invested in the Permian Basin, with the remainder in the Mid-Continent. We regularly review our capital expenditures throughout the year and will adjust our investments based on increases or decreases in our cash flow. See ***Long-Term Debt****—Bank Debt* below for further information regarding our credit facility.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations. While we expect pending legislation and regulations to increase the cost of business, we do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending legislative or regulatory changes that would have a material impact. However, compliance with new legislation and regulations could increase our costs and negatively affect demand for oil or gas and result in a material adverse effect on our financial position or operations. See Item 1A **RISK FACTORS** for a description of risks related to current and potential future environmental and safety regulations and requirements that could adversely affect our operations and financial condition.

Long-Term Debt

Long-term debt at December 31, 2020 and 2019 consisted of the following:

(in thousands)	December 31, 2020			December 31, 2019		
	Principal	Unamortized Debt Issuance Costs and Discounts (1)	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs and Discounts (1)	Long-term Debt, net
4.375% notes due 2024	$ 750,000	$ (2,672)	$ 747,328	$ 750,000	$ (3,535)	$ 746,465
3.90% notes due 2027	750,000	(5,541)	744,459	750,000	(6,289)	743,711
4.375% notes due 2029	500,000	(4,488)	495,512	500,000	(4,930)	495,070
Total long-term debt	$ 2,000,000	$ (12,701)	$ 1,987,299	$ 2,000,000	$ (14,754)	$ 1,985,246

(1) The 4.375% notes due 2024 were issued at par, therefore, the amounts shown in the table are for unamortized debt issuance costs only. At December 31, 2020, the unamortized debt issuance costs and discount related to the 3.90% notes due 2027 were $4.3 million and $1.3 million, respectively. At December 31, 2020, the unamortized debt issuance costs and discount related to the 4.375% notes due 2029 were $3.9 million and $0.6 million, respectively. At December 31, 2019, the unamortized debt issuance costs and discount related to the 3.90% notes due 2027 were $4.8 million and $1.5 million, respectively. At December 31, 2019, the unamortized debt issuance costs and discount related to the 4.375% notes due 2029 were $4.3 million and $0.6 million, respectively.

Bank Debt

On June 3, 2020, we entered into the First Amendment to Amended and Restated Credit Agreement (the "First Amendment") dated as of February 5, 2019 for our senior unsecured revolving credit facility ("Credit Facility"). The Credit Facility has aggregate commitments of $1.25 billion with an option for us to increase the aggregate commitments to $1.5 billion, and matures on February 5, 2024. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. The First Amendment, among other things: (i) allows up to $3.5 billion of non-cash impairment charge add-backs to Shareholders' Equity for covenant calculation purposes, (ii) institutes traditional anti-cash hoarding provisions (if borrowings are outstanding under the Credit Facility) at a consolidated cash threshold of $175.0 million, (iii) reduces the priority lien debt basket from 15% of Consolidated Net Tangible Assets (as defined in the credit agreement) to a $50.0 million cap, and (iv) adds an acknowledgement and consent to European Union bail-in legislation. As of December 31, 2020, we had no bank borrowings outstanding under the Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $1.248 billion. During the year ended December 31, 2020, we borrowed and repaid an aggregate of $172.0 million on the Credit Facility to meet cash requirements as needed.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR (or an alternate rate determined by the administrative agent for the Credit Facility in accordance with the Credit Facility when LIBOR is no longer available) plus 1.125 - 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 - 1.0%, based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 - 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capitalization ratio of no greater than 65%. As of December 31, 2020, we were in compliance with all of the financial and non-financial covenants.

At December 31, 2020 and 2019, we had $4.3 million and $4.0 million, respectively, of unamortized debt issuance costs associated with our Credit Facility, which were recorded as assets and included in “Other assets” in our Consolidated Balance Sheets. During the year ended December 31, 2020, we incurred $1.5 million in fees paid to the lenders and third-party costs for the First Amendment. The debt issuance costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

On March 8, 2019, we issued $500 million aggregate principal amount of 4.375% senior unsecured notes at 99.862% of par to yield 4.392% per annum. The notes are due March 15, 2029 and interest is payable semiannually on March 15 and September 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.50%.

In April 2017, we issued $750 million aggregate principal amount of 3.90% senior unsecured notes at 99.748% of par to yield 3.93% per annum. These notes are due May 15, 2027 and interest is payable semiannually on May 15 and November 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.01%.

In June 2014, we issued $750 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1. The effective interest rate on these notes, including the amortization of debt issuance costs, is 4.50%.

Our senior unsecured notes are governed by indentures containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2020.

Working Capital Analysis

At December 31, 2020, we had a working capital deficit of $2.9 million, a change of $134.2 million, or 98% from a working capital deficit of $137.1 million at December 31, 2019. Our working capital deficit decreased primarily as a result of the following:

Working Capital Increases

- Cash and cash equivalents increased by $178.4 million as a result of maintaining capital expenditures at a level below our cash flows from operations in order to increase cash on our balance sheet, which we plan to use to initially target debt reduction and continue to fund and increase our regular common stock cash dividend.

- Operations-related accounts payable and accrued liabilities decreased by $153.4 million, primarily due to decreases in: (i) revenue payable due to declines in revenues, (ii) taxes other than income accruals due to decreased prices causing lower production and ad valorem taxes, (iii) trade accounts payable due to decreased activity, and (iv) current asset retirement obligations due to changes in the estimated timing of retirement activities.

- Exploration and development and midstream capital accruals decreased by $66.6 million as a result of our decision to reduce capital expenditures in response to the decline in oil prices and demand.

Working Capital Decreases

- A decrease of $139.8 million from a net current derivative asset to a net current derivative liability. The fair value of derivative instruments fluctuates based on changes in the underlying price indices as compared to the contracted prices included in the derivative instruments.

- Accounts receivable decreased by $116.1 million, primarily due to declines in prices lowering our oil and gas sales receivable.

- Oil and gas well equipment and supplies decreased by $10.7 million.

Accounts receivable are a major component of our working capital and include amounts due from a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies, and other end-users. We conduct credit analyses prior to making any sales to new customers or increasing credit for existing customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary. For properties we operate, we have the right to realize amounts due to us from non-operators by netting the non-operators' share of production revenues from those properties. We routinely assess the recoverability of all material accounts receivable and accrue a reserve to the allowance for credit losses based on our estimation of expected losses over the life of the receivables. Historically, losses associated with uncollectible receivables have not been significant. However, most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry, such as those currently impacting the industry as a result of the COVID-19 pandemic and low commodity prices.

Dividends

A quarterly cash dividend has been paid on our common stock every quarter since the first quarter of 2006. During 2020, our Board of Directors declared four cash dividends of $0.22 per common share, totaling approximately $90.0 million. During 2020, our Board of Directors declared four cash dividends of $20.3125 per preferred share, totaling approximately $4.9 million. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors. See Note 2 to the Consolidated Financial Statements for further information regarding our stock.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2020, our material off-balance sheet arrangements consisted of operating lease agreements for equipment used in connection with our exploration and development activities with lease terms at commencement of 12 months or less. As an accounting policy, we have elected not to apply the recognition requirements of Topic 842 to these leases. As such, we have not recorded any lease liabilities associated with these leases.

Contractual Obligations and Material Commitments

At December 31, 2020, we had the following contractual obligations and material commitments:

	Payments Due by Period				
Contractual obligations (in thousands)	**Total**	**1/1/21 - 12/31/21**	**1/1/22 - 12/31/23**	**1/1/24 - 12/31/25**	**1/1/26 and Thereafter**
Long-term debt - principal (1)	$ 2,000,000	$ —	$ —	$ 750,000	$ 1,250,000
Long-term debt - interest (1)	490,967	81,868	167,875	118,656	122,568
Operating leases (2)	101,749	27,255	31,736	23,687	19,071
Unconditional purchase obligations (3)	18,903	7,854	6,167	4,882	—
Derivative liabilities	163,147	145,398	17,749	—	—
Asset retirement obligation (4)	177,867	12,272	— (4)	— (4)	— (4)
Other long-term liabilities (5)	49,318	4,460	11,028	10,324	23,506
	$ 3,001,951	$ 279,107	$ 234,555	$ 907,549	$ 1,415,145

(1) The interest payments presented above include the accrued interest payable on our long-term debt as of December 31, 2020 as well as future payments calculated using the long-term debt's fixed rates, stated maturity dates, and principal amounts outstanding as of December 31, 2020. See Note 3 to the Consolidated Financial Statements for additional information regarding our debt.

(2) Operating leases include the estimated remaining contractual payments under lease agreements as of December 31, 2020. These lease agreements are primarily comprised of leases for commercial real estate, which consists primarily of office space, and compressor equipment.

(3) Of the total unconditional purchase obligations, $2.3 million represents obligations for the purchase of sand for well completions and $16.6 million represents obligations for firm transportation agreements for gas pipeline capacity.

(4) We have excluded the presentation of the timing of the cash flows associated with our $165.6 million long-term asset retirement obligations because we cannot make a reasonably reliable estimate of the future period of cash settlement. The long-term asset retirement obligation is included in the total asset retirement obligation presented.

(5) Other long-term liabilities include contractual obligations associated with our employee supplemental savings plan, gas balancing liabilities, and other miscellaneous liabilities. All of these liabilities are accrued on our

Consolidated Balance Sheet. The current portion associated with these long-term liabilities is also presented in the table above.

The following discusses various commercial commitments that we have made that may include potential future cash payments if we fail to meet various performance obligations. These are not reflected in the table above, unless otherwise noted.

At December 31, 2020, we had estimated commitments of approximately: (i) $224.2 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $4.3 million to finish midstream construction in progress.

At December 31, 2020, we had firm sales contracts to deliver approximately 470.3 Bcf of gas over the next 10.5 years. If we do not deliver this gas, our estimated financial commitment, calculated using the January 2021 index prices, would be approximately $908.1 million. The value of this commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no material financial commitment will be due based on our current proved reserves and production levels and our ability to make market purchases to fulfill these volumetric obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next 8.0 years. If we do not deliver the committed gas or NGLs, as applicable, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2020, would be approximately $640.7 million. However, we believe no material financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

We have minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. If we do not deliver this gas or oil, as applicable, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2020, would be approximately $104.7 million. Of this total, we have accrued a liability of $4.3 million representing the estimated amount we will have to pay due to insufficient forecasted volumes at particular connection points. This accrual is reflected in the table above in Other long-term liabilities.

We have minimum volume water delivery commitments associated with a water services agreement, which ends in 2030, that was entered into in connection with the sale of certain water infrastructure assets in Eddy County, New Mexico (see Note 13 to the Consolidated Financial Statements for further information regarding this sale). If the water volumes are not delivered by us or third parties, the estimated maximum amount that would be payable by us under this commitment, calculated as of December 31, 2020, would be approximately $64.1 million. However, we believe no material financial commitment will be due based on our forecasted volumes of water delivery and potential delivery of water volumes by third parties.

All of the noted commitments were routine and made in the ordinary course of our business.

Taking into account current commodity prices and anticipated levels of production, we believe that our net cash flow generated from operations and our other capital resources will be adequate to meet future obligations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Discussion and analysis of our financial condition and results of operation are based on our Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Our significant accounting policies are described in Note 1 to our Consolidated Financial Statements. We have identified the following policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Oil and Gas Reserves

The process of estimating quantities of oil and gas reserves is complex, requiring judgment and interpretation in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time due to numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

At year-end 2020, 16% of our total proved reserves are categorized as proved undeveloped reserves. Our engineers review and revise these reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost associated with our oil and gas properties. Changes in estimates of reserve quantities and commodity prices will cause corresponding changes in depletion expense, or in some cases, a full cost ceiling impairment charge. See ***Full Cost Accounting*** below for further information regarding the ceiling limitation calculation. See **SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)** in Item 8 for additional reserve data.

Full Cost Accounting

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the acquisition, exploration, and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling test impairment. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Income Taxes

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance.

We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 to the Consolidated Financial Statements for additional information regarding our income taxes.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk including the risk of loss arising from adverse changes in commodity prices and interest rates.

Price Fluctuations

Our major market risk is pricing applicable to our oil, gas, and NGL production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil, gas, and NGL production has been volatile and unpredictable. During 2020, our total production revenue was comprised of 66% oil sales, 16% gas sales, and 18% NGL sales. The following table shows how hypothetical changes in the realized prices we receive for our commodity sales may have impacted revenue for the period indicated. See **MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—*Market Conditions*** for further information regarding prices.

	Change in Realized Price		Impact on Revenue Year Ended December 31, 2020
			(in thousands)
Oil	± $1.00	per barrel	± $28,087
Gas	± $0.10	per Mcf	± $23,263
NGL	± $1.00	per barrel	± $25,554
			± $76,904

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At December 31, 2020, we had oil and gas derivatives covering a portion of our 2021 and 2022 production, which were recorded as current and non-current assets and liabilities on our Consolidated Balance Sheet. At December 31, 2020, our oil and gas derivatives had a gross asset fair value of $9.2 million and a gross liability fair value of $163.1 million. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

While these contracts limit the downside risk of adverse price movements, they may also limit future cash flow from favorable price movements. The following table shows how a hypothetical ± 10% change in the underlying forward prices used to calculate the fair value of our derivatives may have impacted the fair value as of December 31, 2020.

	Change in Forward Price	Impact on Fair Value December 31, 2020	
		(in thousands)	
Oil	-10%	$	71,853
Oil	+10%	$	(74,237)
Gas	-10%	$	23,760
Gas	+10%	$	(24,515)

Interest Rate Risk

At December 31, 2020, our long-term debt consisted of $750 million of 4.375% senior unsecured notes that mature on June 1, 2024, $750 million of 3.90% senior unsecured notes that mature on May 15, 2027, and $500 million of 4.375% senior unsecured notes that mature on March 15, 2029. Because all of our outstanding long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. See Note 3 and Note 5 to the Consolidated Financial Statements for additional information regarding our debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors Cimarex Energy Co.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2020 and 2019, the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Financial Accounting Standards Board Accounting Standards Codification Topic 842, Leases.

Basis for Opinion

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

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

Critical Audit Matter

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

Impact of estimated oil and gas reserves related to proved oil and gas properties on depletion expense and the ceiling test calculation

As discussed in Note 1 to the consolidated financial statements, the Company calculates depletion expense for its proved oil and gas properties using the units-of-production method whereby capitalized costs, including estimated future development costs and asset retirement costs, are amortized over total estimated proved reserves. The Company is required to perform a ceiling test calculation on a quarterly basis, and the applicable ceiling limitation is equal to the sum of: (1) the present value discounted at 10% of estimated future net revenues from proved reserves, (2) the cost of properties not being amortized, and (3) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. If the net capitalized cost of oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. For the year ended December 31, 2020, the Company recorded depletion expense related to proved oil and gas properties of $625.5 million and recorded ceiling test impairments of $1,638.3 million. The Company's internal Corporate Reservoir Engineering group prepares estimates of the Company's proved oil and gas reserves. The Company also engages an independent petroleum engineering consulting firm to perform an independent evaluation of a portion of those proved oil and gas reserve estimates.

We identified the impact of the estimate of proved oil and gas reserves used in the determination of depletion expense and the ceiling test calculation as a critical audit matter. There is a high degree of subjectivity in evaluating the estimate of proved oil and gas reserves as auditor judgment was required to evaluate the assumptions used by the Company related to forecasts of production, future operating costs and future development costs, and oil and gas prices inclusive of market differentials.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the process for estimating oil and gas reserves for proved oil and gas properties, including controls over the development of the forecasts of production, future operating costs and future development costs, and oil and gas prices. We evaluated (1) the professional qualifications of the internal Corporate Reservoir Engineering group as well as the engineer assigned to the Company by the independent petroleum engineering consulting firm engaged by the Company, (2) the knowledge, skills, and ability of the Company's internal Corporate Reservoir Engineering group and the independent petroleum engineering consulting firm and the engineer assigned to the Company and (3) the objectivity of the independent petroleum engineering consulting firm and the engineer assigned to the Company. We assessed the methodology used by the Company's internal Corporate Reservoir Engineering group to estimate proved oil and gas reserves and the methodology used by the independent petroleum engineering consulting firm to evaluate those reserve estimates for consistency with industry and regulatory standards. We evaluated the assumptions of forecasts of production, future operating costs and future development costs used by the Company's internal Corporate Reservoir Engineering group by comparing them to the Company's historical actual results. We evaluated the oil and gas prices used by the Company's internal Corporate Reservoir Engineering group by comparing them to publicly available prices and tested the relevant market differentials. We read the findings of the Company's independent petroleum engineering consulting firm in connection with our evaluation of the Company's reserve estimates. We analyzed the depletion expense calculation for compliance with regulatory standards, and recalculated it. We also analyzed the ceiling test impairment calculation for compliance with regulatory standards. In addition, we performed a calculation of the ceiling test impairment and compared our results with the Company's results.

/s/ KPMG LLP

We have served as the Company's auditor since 2002.

Denver, Colorado
February 23, 2021

CIMAREX ENERGY CO.
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share information)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 273,145	$ 94,722
Accounts receivable, net of allowance:		
Trade	49,650	57,879
Oil and gas sales	271,141	384,707
Gas gathering, processing, and marketing	11,694	5,998
Oil and gas well equipment and supplies	37,150	47,893
Derivative instruments	6,848	17,944
Prepaid expenses	7,113	10,759
Other current assets	597	1,584
Total current assets	657,338	621,486
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	21,281,840	20,678,334
Unproved properties and properties under development, not being amortized	1,142,183	1,255,908
	22,424,023	21,934,242
Less—accumulated depreciation, depletion, amortization, and impairment	(18,987,354)	(16,723,544)
Net oil and gas properties	3,436,669	5,210,698
Fixed assets, net of accumulated depreciation of $455,815 and $389,458, respectively	436,101	519,291
Goodwill	—	716,865
Derivative instruments	2,342	580
Deferred income taxes	20,472	—
Other assets	69,067	71,109
	$ 4,621,989	$ 7,140,029
Liabilities, Redeemable Preferred Stock, and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 21,902	$ 36,280
Gas gathering, processing, and marketing	22,388	12,740
Accrued liabilities:		
Exploration and development	50,014	112,228
Taxes other than income	29,051	54,446
Other	201,784	252,304
Derivative instruments	145,398	16,681
Revenue payable	130,637	207,939
Operating leases	59,051	66,003
Total current liabilities	660,225	758,621
Long-term debt:		
Principal	2,000,000	2,000,000
Less—unamortized debt issuance costs and discounts	(12,701)	(14,754)
Long-term debt, net	1,987,299	1,985,246
Deferred income taxes	—	338,424
Asset retirement obligation	165,595	154,045
Derivative instruments	17,749	1,018
Operating leases	134,705	184,172
Other liabilities	66,181	60,742
Total liabilities	3,031,754	3,482,268
Commitments and contingencies (Note 10)		
Redeemable preferred stock - 8.125% Series A Cumulative Perpetual Convertible Preferred Stock, $0.01 par value, 28,165 shares authorized and issued and 62,500 shares authorized and issued, respectively (Note 2)	36,781	81,620
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 102,866,806 and 102,144,577 shares issued, respectively	1,029	1,021
Additional paid-in capital	3,211,562	3,243,325
(Accumulated deficit) retained earnings	(1,659,137)	331,795
Total stockholders' equity	1,553,454	3,576,141
	$ 4,621,989	$ 7,140,029

See accompanying notes to Consolidated Financial Statements.

CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except per share information)

	Years Ended December 31, 2020	2019	2018
Revenues:			
Oil sales	$ 999,682	$ 1,660,210	$ 1,398,813
Gas and NGL sales	513,006	661,711	898,832
Gas gathering and other	47,842	42,454	41,180
Gas marketing	(1,935)	(1,406)	192
	1,558,595	2,362,969	2,339,017
Costs and expenses:			
Impairment of oil and gas properties	1,638,329	618,693	—
Depreciation, depletion, and amortization	695,954	882,173	590,473
Asset retirement obligation	14,653	8,586	7,142
Impairment of goodwill	714,447	—	—
Production	285,324	339,941	296,189
Transportation, processing, and other operating	213,366	238,259	211,463
Gas gathering and other	23,591	23,294	28,327
Taxes other than income	79,699	148,953	125,169
General and administrative	111,005	95,843	77,843
Stock-based compensation	29,895	26,398	22,895
Loss (gain) on derivative instruments, net	35,534	76,850	(85,959)
Other operating expense, net	839	19,305	18,507
	3,842,636	2,478,295	1,292,049
Operating (loss) income	(2,284,041)	(115,326)	1,046,968
Other (income) and expense:			
Interest expense	92,914	93,386	68,224
Capitalized interest	(50,030)	(56,232)	(20,855)
Loss on early extinguishment of debt	—	4,250	—
Other, net	(540)	(5,741)	(22,908)
(Loss) income before income tax	(2,326,385)	(150,989)	1,022,507
Income tax (benefit) expense	(358,927)	(26,370)	230,656
Net (loss) income	$ (1,967,458)	$ (124,619)	$ 791,851
Earnings (loss) per share to common stockholders:			
Basic	$ (19.73)	$ (1.33)	$ 8.32
Diluted	$ (19.73)	$ (1.33)	$ 8.32
Comprehensive (loss) income:			
Net (loss) income	$ (1,967,458)	$ (124,619)	$ 791,851
Other comprehensive (loss) income:			
Change in fair value of investments, net of tax of $0, $(222), and $(425), respectively	—	(755)	(1,444)
Total comprehensive (loss) income	$ (1,967,458)	$ (125,374)	$ 790,407

See accompanying notes to Consolidated Financial Statements.

CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2020	**2019**	**2018**
Cash flows from operating activities:			
Net (loss) income	$ (1,967,458)	$ (124,619)	$ 791,851
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Impairment of oil and gas properties	1,638,329	618,693	—
Depreciation, depletion, and amortization	695,954	882,173	590,473
Asset retirement obligation	14,653	8,586	7,142
Impairment of goodwill	714,447	—	—
Deferred income taxes	(358,896)	(26,902)	233,280
Stock-based compensation	29,895	26,398	22,895
Loss (gain) on derivative instruments, net	35,534	76,850	(85,959)
Settlements on derivative instruments	119,247	(13,131)	(24,429)
Loss on early extinguishment of debt	—	4,250	—
Changes in non-current assets and liabilities	7,189	(2,797)	(1,779)
Other, net	15,305	14,639	105
Changes in operating assets and liabilities:			
Accounts receivable	116,492	65,128	5,421
Other current assets	5,134	(739)	(1,957)
Accounts payable and other current liabilities	(161,658)	(184,563)	13,951
Net cash provided by operating activities	904,167	1,343,966	1,550,994
Cash flows from investing activities:			
Oil and gas capital expenditures	(594,796)	(1,245,457)	(1,540,305)
Acquisition of oil and gas properties	(11,878)	(288,781)	(26,278)
Other capital expenditures	(44,302)	(73,693)	(103,459)
Sales of oil and gas assets	69,983	28,945	580,652
Sales of other assets	2,118	1,104	3,772
Net cash used by investing activities	(578,875)	(1,577,882)	(1,085,618)
Cash flows from financing activities:			
Borrowings of long-term debt	172,000	2,619,310	—
Repayments of long-term debt	(172,000)	(2,990,000)	—
Financing, underwriting, and debt redemption fees	(1,566)	(11,798)	(100)
Finance lease payments	(4,842)	(3,869)	—
Dividends paid	(92,976)	(81,709)	(55,243)
Repurchase of redeemable preferred stock	(43,029)	—	—
Employee withholding taxes paid upon the net settlement of equity-classified stock awards	(4,456)	(5,229)	(12,142)
Proceeds from exercise of stock options	—	1,267	2,241
Net cash used by financing activities	(146,869)	(472,028)	(65,244)
Net change in cash and cash equivalents	178,423	(705,944)	400,132
Cash and cash equivalents at beginning of period	94,722	800,666	400,534
Cash and cash equivalents at end of period	$ 273,145	$ 94,722	$ 800,666

See accompanying notes to Consolidated Financial Statements.

CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except per share information)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2017	95,437	$ 954	$ 2,764,384	$ (199,259)	$ 2,199	$ 2,568,278
Dividends paid on stock awards subsequently forfeited	—	—	34	18	—	52
Dividends declared on common stock ($0.68 per share)	—	—	(15,196)	(49,725)	—	(64,921)
Net income	—	—	—	791,851	—	791,851
Unrealized change in fair value of investments, net of tax	—	—	—	—	(1,444)	(1,444)
Issuance of restricted stock awards	593	6	(6)	—	—	—
Common stock reacquired and retired	(139)	—	(12,142)	—	—	(12,142)
Restricted stock forfeited or canceled and retired	(168)	(2)	2	—	—	—
Exercise of stock options	33	—	2,241	—	—	2,241
Stock-based compensation	—	—	45,871	—	—	45,871
Balance, December 31, 2018	95,756	958	2,785,188	542,885	755	3,329,786
Dividends paid on stock awards subsequently forfeited	—	—	8	18	—	26
Dividends declared on common stock ($0.80 per share)	—	—	61	(81,411)	—	(81,350)
Dividends declared on redeemable preferred stock ($81.25 per share)	—	—	—	(5,078)	—	(5,078)
Net loss	—	—	—	(124,619)	—	(124,619)
Issuance of stock for Resolute Energy acquisition (Note 13)	5,652	56	412,959	—	—	413,015
Unrealized change in fair value of investments, net of tax	—	—	—	—	(755)	(755)
Issuance of restricted stock awards	946	9	(9)	—	—	—
Common stock reacquired and retired	(105)	(1)	(5,228)	—	—	(5,229)
Restricted stock forfeited or canceled and retired	(133)	(1)	1	—	—	—
Exercise of stock options	29	—	1,267	—	—	1,267
Stock-based compensation	—	—	49,078	—	—	49,078
Balance, December 31, 2019	102,145	1,021	3,243,325	331,795	—	3,576,141
Dividends paid on stock awards subsequently forfeited	—	—	32	124	—	156
Dividends declared on common stock ($0.88 per share)	—	—	(67,658)	(22,329)	—	(89,987)
Dividends declared on redeemable preferred stock ($81.25 per share)	—	—	(3,592)	(1,269)	—	(4,861)
Return from repurchase of redeemable preferred stock	—	—	1,810	—	—	1,810
Net loss	—	—	—	(1,967,458)	—	(1,967,458)
Issuance of restricted stock awards	1,159	13	(13)	—	—	—
Common stock reacquired and retired	(162)	(2)	(4,454)	—	—	(4,456)
Restricted stock forfeited or canceled and retired	(275)	(3)	3	—	—	—
Stock-based compensation	—	—	42,109	—	—	42,109
Balance, December 31, 2020	102,867	$ 1,029	$ 3,211,562	$ (1,659,137)	$ —	$ 1,553,454

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cimarex Energy Co., a Delaware corporation, is an independent oil and gas exploration and production company. Our operations are located entirely within the United States of America, mainly in Texas, New Mexico, and Oklahoma.

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Our significant accounting policies are discussed below. The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation. Certain amounts in the prior year financial statements have been reclassified to conform to the 2020 financial statement presentation.

Segment Information

We have determined that our business is comprised of only one segment because our gathering, processing, and marketing activities are ancillary to our oil and gas production operations.

Use of Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. Areas of significance requiring the use of management's judgments include the estimation of proved oil and gas reserves used in calculating depletion, the estimation of future net revenues used in computing ceiling test limitations, the estimation of future abandonment obligations used in recording asset retirement obligations, and the assessment of goodwill. Estimates and judgments also are required in determining allowances for credit losses, impairments of unproved properties and other assets, valuation of deferred tax assets, fair value measurements, lease liabilities, and contingencies. We analyze our estimates and base them on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

The process of estimating quantities of oil and gas reserves is complex, requiring judgment and interpretation in the evaluation of all available geological, geophysical, engineering, and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions, and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities of three months or less. Cash equivalents are stated at cost, which approximates market value.

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost and net realizable value, where net realizable value is based on estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Declines in the price of oil and gas well equipment and supplies in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the acquisition, exploration, and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

During the years ended December 31, 2020 and 2019, we recognized ceiling test impairments totaling \$1.64 billion and \$618.7 million, respectively. The impairments resulted primarily from the impact of decreases in the 12-month average trailing prices for oil, natural gas, and NGLs as well as significant basis differentials utilized in determining the estimated future net cash flows from proved reserves. We did not recognize a ceiling test impairment during the year ended December 31, 2018 because the net capitalized cost of our oil and gas properties, as adjusted for income taxes, did not exceed the ceiling limitation. The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur full cost ceiling test impairments in future quarters. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Fixed Assets

Fixed assets consist primarily of gas gathering and plant facilities, water infrastructure, vehicles, airplanes, office furniture, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from 3 to 30 years. Also included in Fixed assets are operating lease right-of-use assets. See Note 10 for additional information regarding our leases.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. In performing the goodwill test, we compare the fair value of our reporting unit with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, an impairment charge is recognized in the amount of this excess, limited to the total amount of goodwill allocated to that reporting unit. We evaluate our goodwill for impairment in the fourth quarter of each year and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our assessment as of October 31, 2019, goodwill was not impaired. However, during the three months ended March 31, 2020 the company's market capitalization declined significantly, caused by macroeconomic and geopolitical conditions including the collapse of oil prices driven by surplus supply and decreased demand caused by the COVID-19 pandemic. In addition, the uncertainty related to oil demand significantly impacted our investment and operating decisions. As a result, we concluded that a triggering event had occurred and we performed an interim quantitative impairment test for goodwill as of March 31, 2020. As a result of that quantitative impairment test, which utilized quoted market prices for our common stock as a basis for determining the fair value of our reporting unit, we concluded that goodwill was fully impaired at March 31, 2020.

The following table reflects components of the change in the carrying amount of goodwill for the year ended December 31, 2020:

(in thousands)		**Year Ended December 31, 2020**
Goodwill balance at January 1, 2020	$	716,865
Resolute acquisition purchase price adjustments (Note 13)		(2,418)
Impairment		(714,447)
Goodwill balance at December 31, 2020	$	—

Revenue Recognition

Oil, Gas, and NGL Sales

Revenue is recognized from the sales of oil, gas, and NGLs when the customer obtains control of the product, when we have no further obligations to perform related to the sale, and when collectability is probable. All of our sales of oil, gas, and NGLs are made under contracts with customers, which typically include variable consideration based on monthly pricing tied to local indices and monthly volumes delivered. The nature of our contracts with customers does not require us to constrain that variable consideration or to estimate the amount of transaction price attributable to future performance obligations for accounting purposes. As of December 31, 2020, we had open contracts with customers with terms of one month to multiple years, as well as "evergreen" contracts that renew on a periodic basis if not canceled by us or the customer. Performance obligations under our contracts with customers are typically satisfied at a point-in-time through monthly delivery of oil, gas, and/or NGLs. Our contracts with customers typically require payment within one month of delivery.

Our gas is sold under various contracts. Under these contracts the gas and its components, including residue gas and NGLs, may be sold to a single purchaser or separate purchasers. Regardless of the contract, we are compensated for the value of the residue gas and NGLs at current market prices for each product. Depending on the specific contract terms, certain gathering, treating, transportation, processing, and other charges may be deducted against the prices we receive for the products. Our oil typically is sold at specific delivery points under contract terms that are common in our industry.

Gas Gathering

When we transport, process, and/or market third-party gas associated with our equity gas, we recognize revenue for the fees charged to third-parties for such services.

Gas Marketing

When we market and sell gas for other working interest owners, we act as agent under short-term sales and supply agreements and may earn a fee for such services. Revenues from such services are recognized as gas is delivered.

Gas Imbalances

Revenue from the sale of gas is recorded on the basis of gas actually sold by or for us. If our aggregate sales volumes for a well are greater (or less) than our proportionate share of production from the well, a liability (or receivable) is established to the extent there are insufficient proved reserves available to make-up the overproduced (or underproduced) imbalance. Imbalances have not been significant in the periods presented.

General and Administrative Expenses

General and administrative expenses are reported net of amounts reimbursed to us by other working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting. General and administrative expense for the year ended December 31, 2020 included $28.7 million in severance expense associated with the voluntary early retirement incentive program that we offered to employees who met certain eligibility criteria in the first quarter of 2020 and the involuntary reduction in workforce program that we carried out in the third quarter of 2020. All of the expense for these programs was recognized in 2020. The remaining liability for these programs at December 31, 2020 is $11.3 million. The majority of this amount will be paid out in 2021, with the final payments expected to be made in 2022.

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment. See Note 4 for additional information regarding our derivative instruments.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. We classify all deferred tax assets and liabilities as non-current. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 for additional information regarding our income taxes.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies and determine when we should record losses for these items based on information available to us. See Note 10 for additional information regarding our contingencies.

Asset Retirement Obligations

We recognize the present value of the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The liability includes costs related to the plugging and abandonment of wells, the removal of facilities and equipment, and site restorations. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and are depleted or depreciated as applicable. Subsequent to initial measurement at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. The current portion of our asset retirement obligations is recorded in “Accrued liabilities — Other” in the accompanying Consolidated Balance Sheets and cash payments for settlements of retirement obligations are classified as cash used in operating activities in the accompanying Consolidated Statements of Cash Flows. See Note 8 for additional information regarding our asset retirement obligations.

Stock-based Compensation

We grant various types of stock-based awards including equity-classified awards such as stock options, restricted stock (including awards with service-based vesting and market condition-based vesting provisions), restricted stock units, and liability-classified awards such as cash-settled phantom stock. We recognize compensation cost related to equity-classified awards based on the estimated grant date fair value of the awards. The grant date fair value of stock option awards is determined using the Black-Scholes option pricing model. The grant date fair value of service-based restricted stock and units is the closing market price of our common stock on the grant date. The grant date fair value of the market condition-based restricted stock incorporates the effect of the market condition using a multiple probability simulation model. Compensation cost related to equity-classified awards is recognized ratably over the applicable vesting period. We recognize compensation cost related to liability-classified awards over the applicable vesting period based on an estimated fair value that is remeasured each reporting period using a multiple probability simulation model. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration, and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized as stock-based compensation expense. See Note 6 for additional information regarding our stock-based compensation.

Earnings (Loss) per Share

We calculate earnings (loss) per share recognizing that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" and, therefore, should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our unvested share-based payment awards, consisting of restricted stock and units, qualify as participating securities. Our participating securities do not have a contractual obligation to share in the losses of the entity and, therefore, net losses are not allocated to them. See Note 7 for additional information regarding our earnings per share.

Lease Accounting

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, *Leases* ("Topic 842"). The FASB subsequently issued various ASUs that provided additional implementation guidance. Topic 842 requires lessees to recognize lease liabilities and right-of-use assets on the balance sheet for contracts that provide lessees with the right to control the use of identified assets for a period of time. The scope of Topic 842 excludes leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources. We adopted Topic 842 effective January 1, 2019, using the modified retrospective method applied to all leases that existed on that date, which resulted in the recognition of lease liabilities of $276.9 million and right-of-use assets of $265.0 million. In connection with adoption we made use of the following practical expedients, which are provided in Topic 842:

- a package of practical expedients to not reassess: 1) whether expired or existing contracts are or contain a lease, 2) lease classification for expired or existing leases, and 3) initial direct costs for existing leases;
- an election not to apply the recognition requirements in Topic 842 to short-term leases (a lease that at commencement date has a lease term of 12 months or less and does not contain a purchase option that the company is reasonably certain to exercise);
- a practical expedient that permits combining lease and nonlease components in a contract and accounting for the combination as a lease (elected by asset class); and
- a practical expedient to not reassess certain land easements in existence prior to January 1, 2019.

2. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2020, there were 102.9 million shares of common stock and 28.2 thousand shares of preferred stock outstanding.

Redeemable Preferred Stocks

In February 2019, our Board of Directors created a new series of preferred stock, par value $0.01 per share, designated as 8.125% Series A Cumulative Perpetual Convertible Preferred Stock (the "Preferred Stock") and authorized 62.5 thousand shares. In March 2019, in conjunction with the Resolute acquisition (see Note 13), we issued all of these shares of Preferred Stock. Prior to this issuance, we had not issued any preferred stock.

Holders of the Preferred Stock are entitled to receive, when, as, and if declared by the Board out of funds of Cimarex legally available for payment, cumulative cash dividends at the annual rate of 8.125% of each share's liquidation preference of $1,000. Dividends on the Preferred Stock are payable quarterly in arrears and accumulate from the most recent date as to which dividends have been paid. In the event of any liquidation, winding up, or dissolution of Cimarex, whether voluntary or involuntary, each holder will be entitled to receive in respect of its shares and to be paid out of the assets of Cimarex legally available for distribution to its stockholders, after satisfaction of liabilities to Cimarex's creditors and any senior stock (of which there is currently none) and before any payment or distribution is made to holders of junior stock (including common stock), the liquidation preference of $1,000 per share, with the total liquidation preference at December 31, 2020 being $28.2 million in the aggregate. Each holder has the right at any time, at its option, to convert any or all of such holder's shares of Preferred Stock at an initial conversion rate of 8.0421 shares of fully paid and nonassessable shares of our common stock and $471.40 in cash per share of Preferred Stock. The initial conversion rate of 8.0421 adjusts upon the occurrence of certain events, including the payment of cash dividends to common shareholders, and is 8.38732 as of December 31, 2020. Additionally, at any time on or after October 15, 2021, we shall have the right, at our option, if the closing sale price of our common stock meets certain criteria, to elect to cause all, and not part, of the outstanding shares of Preferred Stock to be automatically converted into that number of shares of Cimarex common stock for each share of Preferred Stock equal to the conversion rate in effect on the mandatory conversion date as such terms are defined in the Certificate of Designations for the Preferred Stock and $471.40 in cash per share of Preferred Stock. We also have the right at any time to repurchase shares of Preferred Stock through privately negotiated transactions. As a result of the cash redemption features included in the Preferred Stock conversion option, with such conversion not solely within our control, the instruments are classified as "Redeemable preferred stock" in temporary equity on the Consolidated Balance Sheets.

In December 2020, we repurchased 34.3 thousand shares of Preferred Stock, leaving 28.2 thousand shares of 8.125% Series A Cumulative Perpetual Convertible Preferred Stock authorized and issued at December 31, 2020. The book value of the repurchased shares exceeded the aggregate amount Cimarex paid to repurchase the shares by $1.8 million. That amount has been treated as a return from the holders of the Preferred Stock and recorded as an increase to additional paid-in capital (similar to the treatment of dividends declared, which are recorded as a reduction of additional paid-in capital).

Dividends

Common Stock

A quarterly cash dividend has been paid on our common stock every quarter since the first quarter of 2006. In each quarter of 2020, a $0.22 per common share dividend was declared. In each quarter of 2019 a $0.20 per common share dividend was declared. A dividend of $0.18 per common share was declared in both the third and fourth quarters of 2018 and a dividend of $0.16 per common share was declared in both the first and second quarters of 2018. Dividends are paid in the quarter following the quarter of declaration. At December 31, 2020, we had dividends payable to common stockholders of $22.9 million that was included in "Accrued liabilities — Other". Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend. Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital. Nonforfeitable dividends paid on stock awards that subsequently forfeit are reclassified out of retained earnings or additional paid-in capital, as applicable, to compensation expense in the period in which the stock award forfeitures occur. Dividends accrued and unpaid on performance stock awards that are canceled upon completion of the vesting period due to the market condition not being met, are reversed out of retained earnings or additional paid-in capital, as applicable, in the period in which the stock award cancellations occur. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

Preferred Stock

In each quarter of 2020 and 2019 our Board of Directors declared a cash dividend of $20.3125 per share of Preferred Stock. Dividends are paid in the quarter following the quarter of declaration. At December 31, 2020, we had dividends payable to preferred stockholders of $0.6 million that was included in “Accrued liabilities — Other”.

3. LONG-TERM DEBT

Long-term debt at December 31, 2020 and 2019 consisted of the following:

	December 31, 2020			December 31, 2019		
(in thousands)	**Principal**	**Unamortized Debt Issuance Costs and Discounts (1)**	**Long-term Debt, net**	**Principal**	**Unamortized Debt Issuance Costs and Discounts (1)**	**Long-term Debt, net**
4.375% notes due 2024	$ 750,000	$ (2,672)	$ 747,328	$ 750,000	$ (3,535)	$ 746,465
3.90% notes due 2027	750,000	(5,541)	744,459	750,000	(6,289)	743,711
4.375% notes due 2029	500,000	(4,488)	495,512	500,000	(4,930)	495,070
Total long-term debt	$ 2,000,000	$ (12,701)	$ 1,987,299	$ 2,000,000	$ (14,754)	$ 1,985,246

(1) The 4.375% notes due 2024 were issued at par, therefore, the amounts shown in the table are for unamortized debt issuance costs only. At December 31, 2020, the unamortized debt issuance costs and discount related to the 3.90% notes due 2027 were $4.3 million and $1.3 million, respectively. At December 31, 2020, the unamortized debt issuance costs and discount related to the 4.375% notes due 2029 were $3.9 million and $0.6 million, respectively. At December 31, 2019, the unamortized debt issuance costs and discount related to the 3.90% notes due 2027 were $4.8 million and $1.5 million, respectively. At December 31, 2019, the unamortized debt issuance costs and discount related to the 4.375% notes due 2029 were $4.3 million and $0.6 million, respectively.

Bank Debt

On June 3, 2020, we entered into the First Amendment to Amended and Restated Credit Agreement (the “First Amendment”) dated as of February 5, 2019 for our senior unsecured revolving credit facility (“Credit Facility”). The Credit Facility has aggregate commitments of $1.25 billion with an option for us to increase the aggregate commitments to $1.5 billion, and matures on February 5, 2024. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. The First Amendment, among other things: (i) allows up to $3.5 billion of non-cash impairment charge add-backs to Shareholders’ Equity for covenant calculation purposes, (ii) institutes traditional anti-cash hoarding provisions (if borrowings are outstanding under the Credit Facility) at a consolidated cash threshold of $175.0 million, (iii) reduces the priority lien debt basket from 15% of Consolidated Net Tangible Assets (as defined in the credit agreement) to a $50.0 million cap, and (iv) adds an acknowledgement and consent to European Union bail-in legislation. As of December 31, 2020, we had no bank borrowings outstanding under the Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $1.248 billion. During the year ended December 31, 2020, we borrowed and repaid an aggregate of $172.0 million on the Credit Facility to meet cash requirements as needed.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR (or an alternate rate determined by the administrative agent for the Credit Facility in accordance with the Credit Facility when LIBOR is no longer available) plus 1.125 - 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 - 1.0%, based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 - 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capitalization ratio of no greater than 65%. As of December 31, 2020, we were in compliance with all of the financial covenants.

At December 31, 2020 and 2019, we had $4.3 million and $4.0 million, respectively, of unamortized debt issuance costs associated with our Credit Facility, which were recorded as assets and included in “Other assets” in our Consolidated Balance Sheets. During the year ended December 31, 2020, we incurred $1.5 million in fees paid to the lenders and third-party costs for the First Amendment. The debt issuance costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

On March 8, 2019, we issued $500.0 million aggregate principal amount of 4.375% senior unsecured notes at 99.862% of par to yield 4.392% per annum. The notes are due March 15, 2029 and interest is payable semiannually on March 15 and September 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.50%.

In April 2017, we issued $750.0 million aggregate principal amount of 3.90% senior unsecured notes at 99.748% of par to yield 3.93% per annum. These notes are due May 15, 2027 and interest is payable semiannually on May 15 and November 15. The effective interest rate on these notes, including the amortization of debt issuance costs and discount, is 4.01%.

In June 2014, we issued $750.0 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1. The effective interest rate on these notes, including the amortization of debt issuance costs, is 4.50%.

Our senior unsecured notes are governed by indentures containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2020.

4. DERIVATIVE INSTRUMENTS

We periodically use derivative instruments to mitigate volatility in commodity prices. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future cash flow from favorable price changes. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels.

As of December 31, 2020, we have entered into oil and gas collars, oil basis swaps, and oil "roll differential" swaps. Under our collars, we receive the difference between the published index price and a floor price if the index price is below the floor price or we pay the difference between the ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and the ceiling prices. By using a collar, we have fixed the minimum and maximum prices we can receive on the underlying production. Our basis swaps are settled based on the difference between a published index price plus or minus a fixed differential, as applicable, and the applicable local index price under which the underlying production is sold. By using a basis swap, we have fixed the differential between the published index price and certain of our physical pricing points. For our Permian oil production, the basis swaps fix the price differential between the WTI NYMEX (Cushing, Oklahoma) price and the WTI Midland price. For our Permian and Mid-Continent gas production, the contract prices in our collars are consistent with the index prices used to sell our production. Our roll differential swaps are settled based on the difference between the monthly roll differential and a fixed price per Bbl. The monthly roll differential is calculated as the sum of 2/3 of the difference in the WTI NYMEX closing settlement price for the first nearby month futures contract minus the second nearby month futures contract and 1/3 of the difference in the WTI NYMEX calendar month average price and the physical crude oil delivery month price. The following tables summarize our outstanding derivative contracts as of December 31, 2020:

Oil Collars	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2021:					
WTI (1)					
Volume (Bbls)	3,600,000	3,094,000	3,680,000	3,680,000	14,054,000
Weighted Avg Price - Floor	$ 38.06	$ 34.62	$ 34.65	$ 34.65	$ 35.52
Weighted Avg Price - Ceiling	$ 46.45	$ 43.28	$ 44.37	$ 44.37	$ 44.66
2022:					
WTI (1)					
Volume (Bbls)	2,340,000	1,729,000	920,000	—	4,989,000
Weighted Avg Price - Floor	$ 37.31	$ 38.16	$ 40.00	$ —	$ 38.10
Weighted Avg Price - Ceiling	$ 48.41	$ 49.56	$ 49.19	$ —	$ 48.95

(1) The index price for these collars is West Texas Intermediate ("WTI") as quoted on the New York Mercantile Exchange ("NYMEX").

Gas Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2021:					
PEPL (1)					
Volume (MMBtu)	9,000,000	9,100,000	8,280,000	8,280,000	34,660,000
Weighted Avg Price - Floor	$ 1.83	$ 1.89	$ 2.00	$ 2.00	$ 1.93
Weighted Avg Price - Ceiling	$ 2.23	$ 2.28	$ 2.42	$ 2.42	$ 2.33
Perm EP (2)					
Volume (MMBtu)	6,300,000	7,280,000	6,440,000	6,440,000	26,460,000
Weighted Avg Price - Floor	$ 1.50	$ 1.62	$ 1.86	$ 1.86	$ 1.71
Weighted Avg Price - Ceiling	$ 1.79	$ 1.92	$ 2.22	$ 2.22	$ 2.03
Waha (3)					
Volume (MMBtu)	8,100,000	9,100,000	8,280,000	8,280,000	33,760,000
Weighted Avg Price - Floor	$ 1.52	$ 1.61	$ 1.82	$ 1.82	$ 1.69
Weighted Avg Price - Ceiling	$ 1.83	$ 1.93	$ 2.17	$ 2.17	$ 2.03
2022:					
PEPL (1)					
Volume (MMBtu)	5,400,000	1,820,000	—	—	7,220,000
Weighted Avg Price - Floor	$ 2.13	$ 2.40	—	—	$ 2.20
Weighted Avg Price - Ceiling	$ 2.55	$ 2.86	—	—	$ 2.63
Perm EP (2)					
Volume (MMBtu)	3,600,000	1,820,000	—	—	5,420,000
Weighted Avg Price - Floor	$ 2.13	$ 2.40	—	—	$ 2.22
Weighted Avg Price - Ceiling	$ 2.53	$ 2.88	—	—	$ 2.65
Waha (3)					
Volume (MMBtu)	5,400,000	1,820,000	—	—	7,220,000
Weighted Avg Price - Floor	$ 1.98	$ 2.40	—	—	$ 2.09
Weighted Avg Price - Ceiling	$ 2.39	$ 2.86	—	—	$ 2.50

(1) The index price for these collars is Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index ("PEPL") as quoted in Platt's Inside FERC.
(2) The index price for these collars is El Paso Natural Gas Company, Permian Basin Index ("Perm EP") as quoted in Platt's Inside FERC.
(3) The index price for these collars is Waha West Texas Natural Gas Index ("Waha") as quoted in Platt's Inside FERC.

Oil Basis Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2021:					
WTI Midland (1)					
Volume (Bbls)	2,790,000	3,003,000	3,220,000	3,220,000	12,233,000
Weighted Avg Differential (2)	$ 0.03	$ (0.02)	$ (0.08)	$ (0.08)	$ (0.04)
2022:					
WTI Midland (1)					
Volume (Bbls)	1,980,000	1,365,000	644,000	—	3,989,000
Weighted Avg Differential (2)	$ 0.25	$ 0.31	$ 0.38	$ —	$ 0.29

(1) The index price we pay under these basis swaps is WTI Midland as quoted by Argus Americas Crude.
(2) The index price we receive under these basis swaps is WTI as quoted on the NYMEX plus or minus, as applicable, the weighted average differential shown in the table.

Oil Roll Differential Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2021:					
WTI (1)					
Volume (Bbls)	630,000	1,001,000	1,656,000	1,656,000	4,943,000
Weighted Avg Price	$ (0.24)	$ (0.22)	$ (0.10)	$ (0.10)	$ (0.14)
2022:					
WTI (1)					
Volume (Bbls)	1,620,000	1,001,000	644,000	—	3,265,000
Weighted Avg Price	$ (0.10)	$ (0.01)	$ 0.10	$ —	$ (0.03)

(1) The index price used to determine the settlement “roll” is WTI as quoted on the NYMEX.

Derivative Gains and Losses

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly cash settlements (if any) of the instruments. We have elected not to designate our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to our derivative instruments. Consequently, changes in the fair value of our derivative instruments and cash settlements on the instruments are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows. The following table presents the components of "Loss (gain) on derivative instruments, net" for the periods indicated.

	Years Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Decrease (increase) in fair value of derivative instruments, net:			
Gas contracts	$ 56,475	$ (13,114)	$ 15,742
Oil contracts	98,306	76,833	(126,130)
	154,781	63,719	(110,388)
Cash (receipts) payments on derivative instruments, net:			
Gas contracts	(15,476)	(40,114)	(13,794)
Oil contracts	(103,771)	53,245	38,223
	(119,247)	13,131	24,429
Loss (gain) on derivative instruments, net	$ 35,534	$ 76,850	$ (85,959)

Derivative Fair Value

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and are subject to master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our accounting policy is to not offset asset and liability positions in our balance sheets.

The following tables present the amounts and classifications of our derivative assets and liabilities as of December 31, 2020 and 2019, as well as the potential effect of netting arrangements on our recognized derivative asset and liability amounts.

		December 31, 2020	
(in thousands)	**Balance Sheet Location**	**Asset**	**Liability**
Oil contracts	Current assets — Derivative instruments	$ 5,425	$ —
Gas contracts	Current assets — Derivative instruments	1,423	—
Gas contracts	Non-current assets — Derivative instruments	2,342	—
Oil contracts	Current liabilities — Derivative instruments	—	106,507
Gas contracts	Current liabilities — Derivative instruments	—	38,891
Oil contracts	Non-current liabilities — Derivative instruments	—	12,526
Gas contracts	Non-current liabilities — Derivative instruments	—	5,223
Total gross amounts presented in the balance sheet		9,190	163,147
Less: gross amounts not offset in the balance sheet		(8,863)	(8,863)
Net amount		$ 327	$ 154,284

		December 31, 2019	
(in thousands)	**Balance Sheet Location**	**Asset**	**Liability**
Oil contracts	Current assets — Derivative instruments	$ 1,624	$ —
Gas contracts	Current assets — Derivative instruments	16,320	—
Oil contracts	Non-current assets — Derivative instruments	580	—
Oil contracts	Current liabilities — Derivative instruments	—	16,681
Oil contracts	Non-current liabilities — Derivative instruments	—	824
Gas contracts	Non-current liabilities — Derivative instruments	—	194
Total gross amounts presented in the balance sheet		18,524	17,699
Less: gross amounts not offset in the balance sheet		(9,865)	(9,865)
Net amount		$ 8,659	$ 7,834

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We mitigate our exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks do not require us to post collateral for our derivative liability positions, nor do we require our counterparties to post collateral for our benefit. In the future we may enter into derivative instruments with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

5. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Authoritative accounting guidance has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable.

The following table provides fair value measurement information for certain assets and liabilities as of December 31, 2020 and 2019.

	December 31, 2020		December 31, 2019	
(in thousands)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Financial Assets (Liabilities):				
4.375% Notes due 2024	$ (750,000)	$ (818,025)	$ (750,000)	$ (792,225)
3.90% Notes due 2027	$ (750,000)	$ (826,575)	$ (750,000)	$ (778,050)
4.375% Notes due 2029	$ (500,000)	$ (567,250)	$ (500,000)	$ (530,400)
Derivative instruments — assets	$ 9,190	$ 9,190	$ 18,524	$ 18,524
Derivative instruments — liabilities	$ (163,147)	$ (163,147)	$ (17,699)	$ (17,699)

Assessing the significance of a particular input to the fair value measurement requires judgment, including the consideration of factors specific to the asset or liability. The fair value (Level 1) of our fixed rate notes was based on quoted market prices. The fair value of our derivative instruments (Level 2) was estimated using discounted cash flow and option pricing models. These models use certain observable variables including forward prices, volatility curves, interest rates, and credit ratings and spreads. The fair value estimates are adjusted relative to non-performance risk as appropriate. See Note 4 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. Included in “Accrued liabilities — Other” at December 31, 2020 are: (i) accrued operating expenses (e.g. production, transportation, and midstream expenses) of approximately $67.4 million and (ii) accrued general and administrative costs of approximately $46.8 million, which consisted primarily of $34.1 million in regular payroll-related costs and $11.3 million in voluntary early retirement incentive program and involuntary reduction in workforce severance accruals. Included in “Accrued liabilities — Other” at December 31, 2019 are: (i) accrued operating expenses (e.g. production, transportation, and midstream expenses) of approximately $74.7 million and (ii) accrued general and administrative costs, primarily payroll-related, of approximately $43.3 million.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry. We conduct credit analyses prior to making any sales to new customers or increasing credit for existing customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary. For properties we operate, we have the right to realize amounts due to us from non-operators by netting the non-operators’ share of production revenues from those properties.

We routinely assess the recoverability of all material accounts receivable and accrue a reserve to the allowance for credit losses based on our estimation of expected losses over the life of the receivables. At December 31, 2020 and 2019, the allowance for credit losses totaled $2.6 million and $3.6 million, respectively.

Major Customers

In each of the years ended December 31, 2020, 2019, and 2018, we made sales to two customers that each amounted to 10% or more of our consolidated revenues for the respective year. Sales to those two customers accounted for 26% and 23%, respectively, of our consolidated revenues in 2020, 29% and 25%, respectively, of our consolidated revenues in 2019, and 21% and 23%, respectively, of our consolidated revenues in 2018.

If any one of our major customers were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production. If multiple significant customers were to discontinue purchasing our production, we believe there could be some initial challenges, but we have ample alternative markets to handle any sales disruption.

6. STOCK-BASED AND OTHER COMPENSATION

Equity Incentive Plan

Our 2019 Equity Incentive Plan (the “2019 Plan”) was approved by stockholders in May 2019. Outstanding awards under previous plans were not impacted, but no additional awards will be made under the previous plans. A total of 6.3 million shares of common stock may be issued under the 2019 Plan, including shares available from the previous plans. The 2019 Plan provides for grants of options, stock appreciation rights, restricted stock, restricted stock units, performance stock units, cash awards, and other stock-based awards.

Stock-based Compensation Cost

We have recognized stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

	Years Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Restricted stock awards:			
Performance stock awards	$ 17,338	$ 21,590	$ 23,083
Service-based stock awards	26,014	25,611	20,385
	43,352	47,201	43,468
Stock option awards	1,460	1,903	2,456
Total stock-based compensation cost	44,812	49,104	45,924
Less amounts capitalized to oil and gas properties	(14,917)	(22,706)	(23,029)
Stock-based compensation expense	$ 29,895	$ 26,398	$ 22,895

Periodic stock-based compensation expense will fluctuate based on the grant date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. Our accounting policy is to account for forfeitures in compensation cost when they occur. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration, and development activities, such amounts are capitalized to oil and gas properties. The amount capitalized to oil and gas properties decreased as a percentage of total stock-based compensation cost in 2020 as compared to 2019 and 2018 due to reduced acquisition, exploration, and development activities in 2020 as a result of the low oil prices and demand destruction experienced in 2020 stemming from the COVID-19 pandemic and OPEC and other countries' actions. The decreased capitalization caused the overall stock-based compensation expense to increase.

Restricted Stock

The following table provides information about restricted stock awards granted during the last three years.

	Years Ended December 31,								
	2020			2019			2018		
	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
Performance stock awards	311,974	$	29.84	264,393	$	47.66	123,533	$	90.26
Service-based stock awards	846,918	$	35.54	681,988	$	45.88	469,438	$	81.29
Total restricted stock awards	1,158,892	$	34.01	946,381	$	46.38	592,971	$	83.16

Performance stock awards are granted to eligible executives and are subject to service and market condition-based vesting determined by our stock price performance relative to defined peer groups' stock price performance. The performance stock awards granted in 2018 and 2019 are equity-classified awards and after three years of continued service, an executive will be entitled to vest in 0% to 200% of the award depending on our stock price performance, with the vested amount paid in shares. For the performance stock awards granted in 2020, after three years of continued service, an executive will be entitled to vest in 0% to 200% of the award depending on our stock price performance, with the vested amount up to 100% paid in shares and any vested amount above 100% paid in cash. The share-settled portion of these awards are equity-classified awards and the cash-settled portion of these awards are liability-classified awards.

We recognize compensation cost related to the equity-classified portion of performance stock awards ratably over the applicable vesting period based on the estimated grant date fair value of the awards, which is calculated using a multiple probability simulation model incorporating the effect of the market condition. We recognize compensation cost related to the liability-classified portion of performance stock awards over the applicable vesting period based on an estimated fair value that is remeasured each reporting period using a multiple probability simulation model incorporating the effect of the market condition. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes.

Service-based stock awards are granted to eligible employees and non-employee directors and have vesting schedules ranging from one to five years. The majority of our service-based stock awards cliff vest five years from the grant date. We recognize compensation cost for the service-based stock awards based upon the grant date fair value of the award, which is the closing market price of our common stock on the grant date. Such costs are recognized ratably over the applicable vesting period.

The following table provides information on restricted stock activity during the year.

	Service-based			Performance (subject to market conditions)		
	Number of Shares		Weighted Average Grant Date Fair Value	Number of Shares		Weighted Average Grant Date Fair Value
Outstanding as of January 1, 2020	1,639,069	$	74.51	664,977	$	72.99
Vested	(237,616)	$	94.23	(205,746)	$	82.83
Granted	846,918	$	35.54	311,974	$	29.84
Canceled (1)	—	$	—	(119,521)	$	89.46
Forfeited	(155,450)	$	78.43	—	$	—
Outstanding as of December 31, 2020	2,092,921	$	56.21	651,684	$	46.20

(1) These performance shares were canceled since the market condition was not satisfied as of the end of the performance period.

The total vest date market value of restricted stock that vested during the years ended December 31, 2020, 2019, and 2018 was $12.0 million, $15.1 million, and $34.1 million, respectively.

Unrecognized compensation cost related to equity-classified unvested restricted stock at December 31, 2020 was approximately $84.2 million. We expect to recognize this cost over a weighted average period of 2.6 years. As of December 31, 2020, the fair value of the unvested liability-classified performance stock awards was $3.5 million and the associated vested liability was $70 thousand. The vested liability is included in “Other liabilities”.

Restricted Units

As of December 31, 2020 and 2019, we had 8,838 restricted units outstanding. These represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

Stock Options

Options outstanding as of December 31, 2020 expire seven years from the grant date and have service-based vesting whereby the awards vest in increments of one-third, generally on each of the first three anniversary dates of the grant. The exercise price for an option under the 2019 Plan and the plan in effect immediately prior to the 2019 Plan, is at least equal to the closing price of our common stock on the date of grant. The previous plans provided that all grants have an exercise price of the average of the high and low prices of our common stock on the date of grant.

We recognize compensation cost related to options based on the estimated grant date fair value of the award and it is recognized ratably over the applicable vesting period. We estimate the grant date fair value using the Black-Scholes option pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the expected years until exercise. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

The following table provides information regarding options granted during the last three years, including the assumptions used to determine the fair value of those options.

	Years Ended December 31,		
	2020	2019	2018
Options granted	194,900	132,900	92,050
Weighted average grant date fair value	$ 12.61	$ 12.14	$ 26.71
Weighted average exercise price	$ 34.06	$ 42.78	$ 83.28
Total fair value (in thousands)	$ 2,458	$ 1,613	$ 2,458
Expected years until exercise	4.9	4.9	5.0
Expected stock volatility	53.9 %	37.1 %	34.7 %
Dividend yield	2.6 %	1.9 %	0.9 %
Risk-free interest rate	0.4 %	1.4 %	2.7 %

The following table provides information regarding outstanding stock options as of December 31, 2020 and changes during the year.

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2020	495,538	$ 87.17		
Exercised	—	$ —		
Granted	194,900	$ 34.06		
Canceled	(107,025)	$ 94.29		
Forfeited	(36,036)	$ 55.69		
Outstanding as of December 31, 2020	547,377	$ 68.94	4.6 years	$ 711
Exercisable as of December 31, 2020	271,827	$ 99.38	3.0 years	$ —

The following table provides information regarding options exercised and the grant date fair value of options vested.

	Years Ended December 31,		
(in thousands)	2020	2019	2018
Cash received from option exercises	$ —	$ 1,267	$ 2,241
Intrinsic value of options exercised	$ —	$ 425	$ 1,030
Grant date fair value of options vested	$ 1,855	$ 2,262	$ 2,547

The following table provides information regarding non-vested stock options as of December 31, 2020 and changes during the year.

	Number of Options	Weighted Average Grant Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2020	208,255	$ 17.60	$ 58.47
Vested	(91,569)	$ 20.26	$ 66.47
Granted	194,900	$ 12.61	$ 34.06
Forfeited	(36,036)	$ 16.74	$ 55.69
Non-vested as of December 31, 2020	275,550		

As of December 31, 2020, there was $3.2 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost over a weighted average period of 2.2 years.

Other Compensation

We maintain and sponsor a contributory 401(k) plan for our employees. Employer contributions related to the plan were $8.2 million, $8.7 million, and $13.1 million for 2020, 2019, and 2018, respectively. Employer discretionary contributions were included in the 2018 amount. No such employer discretionary contributions were accrued for 2020 or 2019.

7. EARNINGS (LOSS) PER SHARE

The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below. Earnings (loss) per share are based on actual figures rather than the rounded figures presented.

(in thousands, except per share information)	Year Ended December 31, 2020 Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net loss	$ (1,967,458)		
Plus: return from repurchase of redeemable preferred stock	1,810		
Less: dividends attributable to participating securities (1)	(1,808)		
Less: redeemable preferred stock dividends	(4,861)		
Basic loss per share			
Loss available to common stockholders	(1,972,317)	99,952	$ (19.73)
Effects of dilutive securities			
Dilutive securities (2)	—	—	
Diluted loss per share			
Loss available to common stockholders and assumed conversions	$ (1,972,317)	99,952	$ (19.73)

(in thousands, except per share information)	Year Ended December 31, 2019 Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net loss	$ (124,619)		
Less: dividends attributable to participating securities (1)	(1,519)		
Less: redeemable preferred stock dividends	(5,078)		
Basic loss per share			
Loss available to common stockholders	(131,216)	98,789	$ (1.33)
Effects of dilutive securities			
Dilutive securities (2)	—	—	
Diluted loss per share			
Loss available to common stockholders and assumed conversions	$ (131,216)	98,789	$ (1.33)

(in thousands, except per share information)	Year Ended December 31, 2018 Income (Numerator)	Shares (Denominator)	Per-Share Amount
Net income	$ 791,851		
Less: dividends and net income attributable to participating securities	(11,087)		
Basic earnings per share			
Income available to common stockholders	780,764	93,793	$ 8.32
Effects of dilutive securities			
Dilutive securities (2)	3	27	
Diluted earnings per share			
Income available to common stockholders and assumed conversions	$ 780,767	93,820	$ 8.32

(1) Participating securities do not have a contractual obligation to share in the losses of the entity, therefore, net losses are not attributable to participating securities.
(2) Inclusion of certain potential common shares would have an anti-dilutive effect, therefore, these shares were excluded from the calculations of diluted earnings (loss) per share. Excluded from the calculation for the year ended December 31, 2020 were 547.4 thousand potential common shares from the assumed exercise of employee stock options, 512.4 thousand potential common shares from the assumed conversion of the Preferred Stock, and 8.8 thousand potential common shares from the assumed vesting of incremental shares of unvested restricted stock units. Excluded from the calculation for the year ended December 31, 2019 were 491.1 thousand potential common shares from the assumed exercise of employee stock options, 426.4 thousand potential common shares from the assumed conversion of the Preferred Stock, and 37.4 thousand potential common shares from the assumed vesting of incremental shares of unvested restricted stock awards. Excluded from the calculation for the year ended December 31, 2018 were 392.8 thousand potential common shares from assumed exercise of employee stock options. See Note 2 for further information regarding our Preferred Stock and Note 6 for further information regarding our stock awards.

8. ASSET RETIREMENT OBLIGATIONS

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2020 and 2019.

(in thousands)	2020	2019
Asset retirement obligation at January 1,	$ 181,869	$ 166,904
Liabilities incurred	4,491	21,511
Liability settlements and disposals	(21,922)	(19,595)
Accretion expense	7,485	7,499
Revisions of estimated liabilities	5,944	5,550
Asset retirement obligation at December 31,	177,867	181,869
Less current obligation	12,272	27,824
Long-term asset retirement obligation	$ 165,595	$ 154,045

Liabilities incurred during the year ended December 31, 2019 included $9.4 million for the Resolute acquisition.

9. INCOME TAXES

The components of our provision for income taxes were as follows:

	Years Ended December 31,		
(in thousands)	2020	2019	2018
Current taxes:			
Federal benefit	$ (198)	$ —	$ (3,007)
State expense	167	532	383
	(31)	532	(2,624)
Deferred taxes:			
Federal (benefit) expense	(323,597)	(24,055)	211,717
State (benefit) expense	(35,299)	(2,847)	21,563
	(358,896)	(26,902)	233,280
	$ (358,927)	$ (26,370)	$ 230,656

Federal income tax expense (benefit) for the years presented differs from the amounts that would be provided by applying the U.S. federal income tax rate, primarily due to the effect of state income taxes, non-deductible expenses, changes in tax laws and tax rates enacted in the period, and changes in valuation allowances. Reconciliations of the income tax (benefit) expense calculated at the federal statutory rate of 21% to the total income tax (benefit) expense are as follows:

	Years Ended December 31,		
(in thousands)	2020	2019	2018
Provision at statutory rate	$ (488,541)	$ (31,708)	$ 214,726
Effect of state taxes	(29,467)	(1,717)	18,795
Acquisition-related costs	—	1,318	—
Tax credits and other permanent differences	1,365	2,548	1,583
Change in valuation allowance, net	(4,221)	—	(1,376)
Stock-based compensation	11,903	3,189	(3,072)
Goodwill impairment	150,034	—	—
Income tax (benefit) expense	$ (358,927)	$ (26,370)	$ 230,656

The components of net deferred taxes are as follows:

	December 31,	
(in thousands)	2020	2019
Assets:		
Stock-based compensation and other accrued amounts	$ 59,659	$ 31,521
Net operating loss and other carryforwards, net of valuation allowance	456,613	454,743
Credit carryforward, net of valuation allowance	4,223	3,936
	520,495	490,200
Liabilities:		
Property, plant and equipment	(500,023)	(828,624)
Net deferred tax assets (liabilities)	$ 20,472	$ (338,424)

On March 1, 2019, we completed the acquisition of Resolute. For federal income tax purposes, the acquisition was a tax-free merger whereby Cimarex acquired carryover tax basis in Resolute's tax assets and liabilities. See Note 13 for more information regarding the purchase price allocation. The net deferred tax liability recorded in connection with the acquisition includes certain deferred tax assets net of valuation allowances. The acquired tax attributes include federal net operating loss, capital loss, and enhanced oil recovery tax credit carryforwards.

Since the acquisition resulted in a greater than 50% ownership change in Resolute, the tax attributes Cimarex acquired from Resolute are subject to limitation pursuant to Section 382 of the Internal Revenue Code. Our ability to utilize the Resolute net operating losses ("NOLs") and other tax attributes acquired is limited to an annual amount calculated at acquisition plus any net unrealized built-in gains recognized within five years of the ownership change. The annual limitation amount is $19.6 million. The estimated net unrealized built-in gain at December 31, 2019 of $253.9 million was increased to $291.0 million at December 31, 2020, pursuant to filed returns and changes in estimates. As of December 31, 2019, the acquired Resolute federal NOLs were reduced by a $57.6 million valuation allowance. As a result of the increase in the estimated net unrealized built-in gain and the utilization of $13.5 million of Resolute's Section 382 limited tax attributes in Cimarex's 2019 federal income tax return, the valuation allowance was reduced to $34.0 million at December 31, 2020. A full valuation allowance remains on the Resolute acquired capital loss carryforward of $67.2 million and enhanced oil recovery credit carryforwards of $4.0 million to reflect the expected tax effect of the Section 382 limitation. The Resolute federal NOLs will begin to expire in 2033.

At December 31, 2020, we had a U.S. net tax operating loss carryforward (including Resolute) of approximately $1.997 billion, $1.773 billion of which is subject to expiration in years 2032 through 2037 and $224.4 million of which is not subject to expiration. We believe that the carryforward, net of valuation allowance, will be utilized before it expires. At December 31, 2020, we recorded a $1.7 million increase to the valuation allowance related to state net operating losses. The total valuation allowance on state net operating losses at December 31, 2020 was $120.7 million since it is not more likely than not that these additional state net operating losses will be utilized before they expire. We also had enhanced oil recovery and marginal well credits of $4.2 million at December 31, 2020.

When assessing the need for a valuation allowance against a deferred tax asset, both positive and negative evidence is considered when determining the ability to utilize our deferred tax assets. Based on our estimate of the timing of future reversals of existing taxable temporary differences, our estimate of future taxable income exclusive of reversing temporary differences and carryforwards, the length of time before the deferred tax assets associated with the net operating loss carryovers begin to expire, and tax planning strategies that could be implemented to accelerate taxable amounts to utilize expiring carryovers, we believe it is more likely than not that the benefit from the deferred tax asset recorded in the financial statements will be realized. We will continue to assess all available positive and negative evidence to estimate whether sufficient future taxable income will be generated in order to utilize the deferred tax assets. Additional valuation allowances may be required in future periods if additional losses are incurred or other circumstances change.

At December 31, 2020 and 2019, we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2017 through 2019 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open to examination for tax years 2016 through 2019. We do not anticipate the need for any significant income tax payments in the near term.

10. COMMITMENTS AND CONTINGENCIES

Lease Commitments

Effective January 1, 2019, we began accounting for leases in accordance with Topic 842, which requires lessees to recognize lease liabilities and right-of-use assets on the balance sheet for contracts that provide lessees with the right to control the use of identified assets for periods of greater than 12 months. Prior to January 1, 2019, we accounted for leases in accordance with ASC Topic 840, *Leases*, under which operating leases were not recorded on the balance sheet.

Real Estate Leases

We have operating leases for office space in various locations that provide us the right to control the use of the specified office space over the term of the contract. These leases require us to make monthly “base rent” payments, as well as “additional payments” for our share of operating expenses and taxes incurred by the landlord. At our option, the terms of these leases can be renewed for varying periods, and in some cases may be terminated early at our option. As of December 31, 2020, these leases had remaining lease terms ranging from 3.4 to 5.7 years. These leases do not contain residual value guarantees, options to purchase the underlying office space, or terms or covenants that impose restrictions on our ability to pay dividends, incur debt, or enter into additional leases. We have no subleases of office space.

Lease liabilities associated with our real estate leases were recorded at the present value of the estimated future lease payments, after considering the following:

- “Base rent” payments are considered fixed lease payments, while “additional payments” are considered variable lease payments.

- At commencement of each real estate lease we were not reasonably certain to exercise the option to renew or terminate such lease.

- The discount rate used to calculate each lease liability was based on our incremental borrowing rate, which was estimated utilizing trading metrics for our senior unsecured notes as adjusted using relevant market factors to develop a synthetic secured yield curve.

- As an accounting policy we have elected not to separate nonlease components from lease components for our real estate class of assets.

- Where applicable, we determined that the effect of accounting for the right to use land separately from other lease components would be insignificant.

Production-Related Leases

We have operating leases for equipment used in connection with our oil and gas production operations, including well-head compressors, pipeline compressors, and artificial lift mechanisms. These leases provide us the right to control the use of explicitly or implicitly identified equipment during the term of the contract. These leases often include an “evergreen” provision that allows the contract term to continue on a month-to-month basis following expiration of the initial term stated in the contract. As of December 31, 2020, these leases had remaining lease terms ranging from one month to 10.4 years. These leases require us to make monthly payments of fixed amounts, which cover the cost of renting the equipment and, in some cases, the cost of maintaining the leased equipment. These leases do not typically require us to make variable lease payments. These leases do not contain residual value guarantees, options to purchase the underlying equipment, or terms or covenants that impose restrictions on our ability to pay dividends, incur debt, or enter into additional leases. We have no subleases of production-related equipment.

Lease liabilities associated with our production-related operating leases were recorded at the present value of the estimated future lease payments, after considering the following:

- For leases with an evergreen provision, the term of the lease was determined to be the noncancellable period in the contract plus the period beyond the noncancellable period that we believe it is reasonably certain we will need the equipment for operational purposes, limited to the point in time at which both we and the lessor each have the right to terminate the lease without permission from the other party with no more than an insignificant penalty.

- The discount rate used to calculate each lease liability was based on our incremental borrowing rate, which was estimated utilizing trading metrics for our senior unsecured notes as adjusted using relevant market factors to develop a synthetic secured yield curve.

- As an accounting policy, we have elected not to separate nonlease components from lease components for our production-related class of assets.

We have one finance lease, which results from a gathering agreement (the “Gathering Agreement”) on a gathering system. Under terms of the Gathering Agreement, we have the option to acquire a portion of the underlying gathering system upon termination of the Gathering Agreement. We make monthly payments under the Gathering Agreement based on the volume of oil gathered and a gathering rate per barrel, which is adjusted periodically. As of December 31, 2020, this lease had a remaining term of 4.7 years.

Exploration and Development-Related Leases

We have operating leases for equipment used in connection with our exploration and development activities, including drilling rigs, pressure pumping equipment, directional drilling tools, well-control devices, and various pieces of support equipment. These leases provide us the right to control the use of explicitly or implicitly identified equipment during the term of the contract. As of December 31, 2020, these leases had remaining lease terms of 12 months or less. These leases typically require us to make payments in amounts based on the usage of the underlying equipment. These leases do not contain residual value guarantees, options to purchase the underlying equipment, or terms or covenants that impose restrictions on our ability to pay dividends, incur debt, or enter into additional leases. We have no subleases of exploration and development-related equipment.

As an accounting policy, we have elected not to apply the recognition requirements of Topic 842 to our exploration and development-related class of assets with lease terms at commencement of 12 months or less. As such, we have not recorded any lease liabilities associated with our exploration and development-related leases. In addition, as an accounting policy we have elected not to separate nonlease components from lease components for our exploration and development-related class of assets.

Balance Sheet Presentation

The following tables present the amounts and classifications of our estimated right-of-use assets, net and lease liabilities as of December 31, 2020 and 2019:

(in thousands)	**Balance Sheet Location**	**December 31, 2020**	**December 31, 2019**
Operating lease right-of-use assets	Non-current assets — Fixed assets, net	$ 185,118	$ 240,263
Finance lease right-of-use asset	Non-current assets — Other assets	25,052	24,849
Total right-of-use assets		$ 210,170	$ 265,112

(in thousands)	**Balance Sheet Location**	**December 31, 2020**	**December 31, 2019**
Operating lease liabilities — current	Current liabilities — Operating leases	$ 59,051	$ 66,003
Operating lease liabilities — non-current	Non-current liabilities — Operating leases	134,705	184,172
Finance lease liability — current	Current liabilities — Accrued liabilities — Other	7,099	7,328
Finance lease liability — non-current	Non-current liabilities — Other liabilities	19,731	18,749
Total lease liabilities		$ 220,586	$ 276,252

Lease Cost and Cash Flows

The following table summarizes estimated total lease cost, which includes amounts recognized in income and amounts capitalized for the indicated periods:

(in thousands)	**Years Ended December 31, 2020**	**Years Ended December 31, 2019**
Finance lease cost:		
Amortization of right-of-use asset	$ 5,286	$ 4,385
Interest on lease liability	1,663	1,719
Operating lease cost:		
Production expense (1)	19,914	20,965
Transportation, processing, and other operating (1)	21,386	17,264
Gas gathering and other expense (1)	991	5,607
General and administrative expense (2)	12,701	12,421
Short-term lease cost (3)	235,840	539,110
Total lease cost	$ 297,781	$ 601,471

(1) Operating lease cost in the table above is composed of costs incurred under production-related leases. These costs are included in the indicated captions on the Consolidated Statements of Operations and Comprehensive Income (Loss).

(2) Operating lease cost in the table above is composed of costs incurred under real estate leases. A majority of these costs are included in the indicated caption on the Consolidated Statements of Operations and Comprehensive Income (Loss). A portion of these costs are capitalized as part of proved properties on the

Consolidated Balance Sheets. These costs include variable lease costs of $3.2 million and $3.1 million for the years ended December 31, 2020 and 2019, respectively.

(3) Short-term lease cost in the table above is composed of costs incurred under leases with terms of 12 months or less for right-of-use assets used in exploration and development activities. Payments under such leases are typically based on usage of the underlying right-of-use asset and, therefore, are also variable lease costs. These costs are capitalized as part of proved properties on the Consolidated Balance Sheets.

The following table summarizes estimated cash paid for our leases for the indicated periods:

	Years Ended December 31,	
(in thousands)	**2020**	**2019**
Cash paid for amounts included in the measurement of lease liabilities:		
Financing cash outflows from finance lease	$ 4,842	$ 3,869
Operating cash outflows from operating leases	$ 53,066	$ 54,044
Cash paid for short-term leases and variable lease payments:		
Operating cash outflows from operating leases	$ 3,169	$ 3,103
Investing cash outflows from operating leases	$ 235,024	$ 551,325

During the years ended December 31, 2020 and 2019, we recognized $42.7 million and $91.7 million, respectively, in right-of-use assets in connection with new operating leases entered into during the period.

The following table presents the weighted-average remaining lease terms and discount rates of our leases as of the indicated dates:

	December 31,	
	2020	**2019**
Weighted-average remaining lease term (in years):		
Finance lease	4.7	5.9
Operating leases	3.9	4.1
Weighted-average discount rate:		
Finance lease	6.3 %	5.7 %
Operating leases	5.0 %	3.9 %

Lease Liability Maturity Analysis

The following table reflects the undiscounted future cash flows utilized in the calculation of the lease liabilities recorded at December 31, 2020:

	December 31, 2020	
(in thousands)	Operating Leases	Finance Lease
January 1, 2021 — December 31, 2021	$ 67,330	$ 7,618
January 1, 2022 — December 31, 2022	61,595	6,666
January 1, 2023 — December 31, 2023	41,567	6,340
January 1, 2024 — December 31, 2024	21,259	6,015
January 1, 2025 — December 31, 2025	8,438	3,829
Remaining periods	14,695	—
Total undiscounted future cash flows	214,884	30,468
Less effects of discounting	(21,128)	(3,638)
Lease liabilities recognized	$ 193,756	$ 26,830

Other Commitments

At December 31, 2020, we had estimated commitments of approximately: (i) $224.2 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $4.3 million to finish midstream construction in progress.

At December 31, 2020, we had firm sales contracts to deliver approximately 470.3 Bcf of gas over the next 10.5 years. If we do not deliver this gas, our estimated financial commitment, calculated using the January 2021 index prices, would be approximately $908.1 million. The value of this commitment will fluctuate due to price volatility and actual volumes delivered.

In connection with gas gathering and processing agreements, we have volume commitments over the next 8.0 years. If we do not deliver the committed gas or NGLs, as applicable, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2020, would be approximately $640.7 million.

We have minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. If we do not deliver this gas or oil, as applicable, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2020, would be approximately $104.7 million. Of this total, we have accrued a liability of $4.3 million representing the estimated amount we will have to pay due to insufficient forecasted volumes at particular connection points.

At December 31, 2020, we have various firm transportation agreements for gas pipeline capacity with end dates ranging from 2021 - 2025 under which we will have to pay an estimated $16.6 million over the remaining terms of the agreements.

We have minimum volume water delivery commitments associated with a water services agreement, which ends in 2030, that was entered into in connection with the sale of certain water infrastructure assets in Eddy County, New Mexico (see Note 13). If we do not deliver the water volumes, the estimated maximum amount that would be payable under this commitment, calculated as of December 31, 2020, would be approximately $64.1 million.

All of the noted commitments were routine and made in the ordinary course of our business.

Litigation

In the ordinary course of business, we are involved with various litigation matters. When a loss contingency exists, we assess whether it is probable that an asset has been impaired or a liability has been incurred and, if so, we determine if the amount of loss can be reasonably estimated, all in accordance with authoritative accounting guidance, and adjust our accruals accordingly. Though some of the related claims may be significant, we believe the resolution of them, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations after consideration of current accruals.

11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (“H&P”) provides contract drilling services to Cimarex. Cimarex incurred drilling costs of approximately $24.9 million, $72.8 million, and $80.1 million related to these services during the years ended December 31, 2020, 2019, and 2018, respectively. The amounts incurred in the years ended December 31, 2020 and 2019 are included in the short-term lease costs disclosed in Note 10. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

12. SUPPLEMENTAL CASH FLOW INFORMATION

	Years Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Cash paid during the period for:			
Interest expense (net of capitalized amounts of $48,306, $49,944, and $19,969, respectively) (1)	$ 41,407	$ 50,601	$ 45,357
Income taxes	$ 300	$ 1,364	$ —
Cash received for income tax refunds	$ 2,118	$ 2,033	$ 760

(1) The year ended December 31, 2019 includes $17.6 million in interest paid upon the redemption of Resolute’s senior notes and credit facility on March 1, 2019.

13. ACQUISITIONS AND DIVESTITURES

On August 31, 2018, we closed on the divestiture of oil and gas properties principally located in Ward County, Texas for which we received $534.6 million in net cash proceeds in 2018, as adjusted for customary closing adjustments to reflect an effective date of April 1, 2018 and transaction costs. This divestiture did not significantly alter the relationship between capitalized costs and proved reserves, therefore, in accordance with the full cost method of accounting, no gain or loss was recognized.

On September 30, 2020, we closed on the sale of certain water infrastructure assets in Eddy County, New Mexico, for which we received net cash proceeds of $68.7 million during 2020, as adjusted for customary closing adjustments and transaction costs. We will be entitled to additional future cash payments from the buyer upon the delivery of certain rights-of-way and if water volumes delivered by Cimarex or third parties meet certain thresholds during the 10 years following the date of sale. See Note 10 for more information on this sale.

On March 1, 2019, we completed the acquisition of Resolute Energy Corporation, an independent oil and gas company focused on the acquisition and development of unconventional oil and gas properties in the Delaware Basin area of the Permian Basin of west Texas. The principal factors considered by management in making this acquisition included: (i) our expectation that Resolute's assets' returns would be competitive with those in our existing portfolio, (ii) the opportunity to apply our experience and learnings from already operating in this area to generating productivity gains from Resolute's properties, (iii) the ability to increase our acreage position in the Delaware Basin, and (iv) the expectation that the acquisition would be financially accretive.

We acquired 100% of the outstanding common shares and voting interests of Resolute in a cash and stock transaction. The acquisition date fair value of the consideration transferred totaled $820.3 million, which consisted of cash, common stock, and a newly created series of preferred stock (see Note 2 for more information on the preferred stock) as follows:

(in thousands)	**Fair Value of Consideration Transferred**
Cash	$ 325,677
Common stock (5,652 shares issued)	413,015
Preferred stock (63 shares issued)	81,620
	$ 820,312

The fair value of the common stock issued as part of the consideration was determined on the basis of the closing market price of Cimarex common stock on the acquisition date. The fair value of the preferred stock issued as part of the consideration was determined using a multiple probability simulation model.

Purchase Price Allocation

The Resolute acquisition has been accounted for as a business combination, using the acquisition method. The following table presents the allocation of the Resolute purchase price to the identifiable assets acquired and liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded to goodwill. The table also presents the adjustments made to the purchase price allocation during the 12-month period following the acquisition date. The purchase price allocation was finalized during the three months ended March 31, 2020. The most significant adjustment was made to reduce the fair value of the unproved oil and gas properties acquired by $30.3 million based on the finalization of the quantity of acres acquired. The tax effect of this adjustment reduced the related deferred income taxes by $6.9 million. The completion of the final Resolute tax returns provided the underlying tax basis of Resolute's assets and liabilities and net operating losses and resulted in a reduction of the deferred tax liability of $24.4 million. The remaining adjustments were related to finalization of working capital balances. The offset to all of the adjustments was goodwill.

The following table sets forth the purchase price allocation:

(in thousands)	March 1, 2019	Adjustments	March 1, 2020
Cash	$ 41,236	$ —	$ 41,236
Accounts receivable	50,739	11,521	62,260
Other current assets	13,280	(1,176)	12,104
Proved oil and gas properties	692,600	—	692,600
Unproved oil and gas properties	1,054,200	(30,314)	1,023,886
Fixed assets	5,355	(32)	5,323
Goodwill	107,341	(13,126)	94,215
Other assets	142	—	142
Current liabilities	(202,735)	1,790	(200,945)
Long-term debt	(870,000)	—	(870,000)
Deferred income taxes	(62,409)	31,337	(31,072)
Asset retirement obligation	(9,437)	—	(9,437)
Total identifiable net assets	$ 820,312	$ —	$ 820,312

In connection with the acquisition, we assumed, and immediately repaid, $870.0 million principal amount of long-term debt consisting of $600.0 million of senior notes and $270.0 million of credit facility borrowings. On March 1, 2019, we repaid Resolute's credit facility borrowings, delivered a notice of optional redemption of Resolute's senior notes for an April 1, 2019 redemption date, and irrevocably deposited with a trustee the full amount of funds to repay the aggregate outstanding senior notes principal balance plus accrued and unpaid interest, incurring a $4.3 million loss on early extinguishment of debt. The cash consideration transferred and the repayment of Resolute's long-term debt were funded using cash on hand and borrowings on our Credit Facility. We subsequently repaid the borrowings on our Credit Facility using the net proceeds from the March 8, 2019 issuance of $500.0 million aggregate principal amount of 4.375% senior unsecured notes.

Goodwill of $94.2 million was recognized in the purchase price allocation principally as a result of recording net deferred tax liabilities arising from the difference between the tax basis and the purchase price allocated to Resolute's assets and liabilities, and anticipated opportunities for cost savings through administrative and operational synergies. We concluded that goodwill was impaired at March 31, 2020 (see Note 1 for more information regarding the goodwill impairment).

Acquisition-related costs incurred were $11.4 million, with $8.4 million expensed in 2019 and $3.0 million expensed in 2018. These costs, which were comprised primarily of advisory and legal fees, are included in the “Other operating expense, net” line item on our Consolidated Statements of Operations and Comprehensive Income (Loss).

Pro Forma Financial Information (Unaudited)

The results of Resolute’s operations have been included in our consolidated financial statements since the March 1, 2019 acquisition date. The following supplemental pro forma information for the years ended December 31, 2019 and 2018 has been prepared to give effect to the Resolute acquisition as if it had occurred on January 1, 2018. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) the depletion of the combined company’s proved oil and gas properties, (ii) the capitalization of interest expense, and (iii) the estimated tax impacts of the pro forma adjustments. Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by Cimarex and Resolute. The pro forma results of operations do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by Cimarex to integrate the Resolute assets. The pro forma financial data has not been adjusted to reflect any other acquisitions or dispositions made during the periods presented as their results were not deemed material.

The pro forma information is not necessarily indicative of the results that might have occurred had the transaction actually taken place on January 1, 2018 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities, and other factors.

	Years Ended December 31,	
(in thousands, except per share information)	**2019**	**2018**
Revenue	$ 2,416,105	$ 2,667,561
Net (loss) income	$ (139,553)	$ 872,140
Net (loss) income per common share:		
Basic	$ (1.47)	$ 8.65
Diluted	$ (1.47)	$ 8.65

CIMAREX ENERGY CO.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil and Gas Reserve Information—Proved reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission ("SEC").

Reserve definitions comply with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of our company. The technical employee primarily responsible for overseeing the reserve estimation process is our Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 26 years of practical experience in reserve evaluation. He has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in his current role for the past 16 years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, performed an independent evaluation of our estimated net reserves representing greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2020. The individual primarily responsible for overseeing the evaluation is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 10 years of experience in oil and gas reservoir studies and reserves evaluations.

Proved reserves are those quantities of oil, gas, and NGLs 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.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The estimation of our proved reserves employs one or more of the following: production trend extrapolation, analogy, volumetric assessment, and material balance analysis. Techniques including review of production and pressure histories, analysis of electric logs and fluid tests, and interpretations of geologic and geophysical data are also involved in this estimation process.

The following table summarizes the trailing twelve-month index prices used in the reserves estimates for 2020, 2019, and 2018. These prices are prior to adjustments for fixed and determinable amounts under provisions in existing contracts, location, grade, and quality.

	December 31,		
	2020	2019	2018
Gas price per Mcf	$ 1.99	$ 2.58	$ 3.10
Oil price per Bbl	$ 39.54	$ 55.67	$ 65.56

The following table sets forth our estimates of our proved, proved developed, and proved undeveloped oil, gas, and NGL reserves as of December 31, 2020, 2019, 2018, and 2017 and changes in our proved reserves for the years ended December 31, 2020, 2019, and 2018. All of our proved reserves are located entirely within the United States of America.

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
Total proved reserves:				
December 31, 2017	1,607,635	137,238	153,860	559,037
Revisions of previous estimates	(132,577)	(4,348)	3,777	(22,667)
Extensions and discoveries	342,810	53,763	47,614	158,512
Purchases of reserves	3	—	—	1
Production	(205,837)	(24,710)	(21,994)	(81,010)
Sales of reserves	(20,713)	(15,405)	(3,821)	(22,678)
December 31, 2018	1,591,321	146,538	179,436	591,195
Revisions of previous estimates	(180,632)	(8,516)	(12,038)	(50,661)
Extensions and discoveries	247,406	41,193	36,834	119,261
Purchases of reserves	129,435	22,628	18,818	63,019
Production	(251,567)	(31,463)	(28,254)	(101,645)
Sales of reserves	(3,818)	(610)	(328)	(1,574)
December 31, 2019	1,532,145	169,770	194,468	619,595
Revisions of previous estimates	(43,504)	(19,692)	(25,488)	(52,430)
Extensions and discoveries	107,322	22,269	16,419	56,575
Purchases of reserves	—	—	—	—
Production	(232,625)	(28,087)	(25,554)	(92,412)
Sales of reserves	(496)	(197)	(27)	(307)
December 31, 2020	1,362,842	144,063	159,818	531,021
Proved developed reserves:				
December 31, 2017	1,334,510	114,116	126,227	462,761
December 31, 2018	1,398,729	116,339	151,566	501,027
December 31, 2019	1,358,329	138,783	166,552	531,722
December 31, 2020	1,190,907	112,785	135,901	447,170
Proved undeveloped reserves:				
December 31, 2017	273,125	23,122	27,633	96,276
December 31, 2018	192,592	30,199	27,870	90,168
December 31, 2019	173,816	30,987	27,916	87,873
December 31, 2020	171,935	31,278	23,917	83,851

Year-end 2020 proved reserves decreased approximately 14% from year-end 2019 proved reserves, to 531.0 MMBOE. Proved gas reserves were 1.36 Tcf, proved oil reserves were 144.1 MMBbls, and proved NGL reserves were 159.8 MMBbls. Our reserves in the Permian Basin accounted for 68% of total proved reserves, with nearly all of the remainder in the Mid-Continent.

During 2020, we added 56.6 MMBOE of proved reserves through extensions and discoveries, primarily in the Permian Basin where we added 47.8 MMBOE, with the remaining 8.8 MMBOE in additions being in the Mid-Continent. We had net negative revisions of 52.4 MMBOE, which consisted of 70.3 MMBOE in downward price revisions, 10.0 MMBOE associated with the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure, and 2.8 MMBOE in net negative technical revisions primarily related to offset completion impacts. These negative revisions were partially offset by 30.7 MMBOE in positive revisions related to decreases in operating expenses.

During 2019, we added 119.3 MMBOE of proved reserves through extensions and discoveries, primarily in the Permian Basin and Mid-Continent where we added 99.9 MMBOE and 19.4 MMBOE, respectively. Additionally, we added 63.0 MMBOE from purchases of reserves, primarily through the Resolute acquisition (see Note 13 to the Consolidated Financial Statements for further information on the acquisition). We had net negative revisions of 50.7 MMBOE, which consisted of 47.2 MMBOE in downward price revisions and 7.0 MMBOE related to increases in operating expenses. In addition, 13.6 MMBOE was associated with the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure. These negative revisions were partially offset by net positive technical revisions of 17.1 MMBOE primarily related to better than expected performance from wells with initial production in late 2018 and positive adjustments to PUD reserves converted to proved developed reserves during 2019.

During 2018, we added 158.5 MMBOE of proved reserves through extensions and discoveries, primarily in the Permian Basin and Mid-Continent where we added 120.3 MMBOE and 38.0 MMBOE, respectively. In addition, we had net negative revisions of 22.7 MMBOE. The revisions included decreases of 38.6 MMBOE for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure and 7.7 MMBOE related to increases in operating expenses. These decreases were partially offset by increases of 2.7 MMBOE in price-related revisions and 20.9 MMBOE of net technical revisions. The majority of the technical revisions were related to better than expected performance from wells with initial production in late 2017 and positive adjustments to PUD reserves converted to proved developed reserves during 2018.

At December 31, 2020, we had PUD reserves of 83.9 MMBOE, down 4.0 MMBOE, or 5%, from 87.9 MMBOE of PUD reserves at December 31, 2019. Changes in our PUD reserves during 2020 are summarized in the table below.

	PUD Reserves (MMBOE)
PUD reserves at December 31, 2019	87.9
Converted to developed	(30.5)
Additions	40.5
Net revisions	(14.0)
PUD reserves at December 31, 2020	83.9

During 2020, we invested $154.9 million to develop and convert 35% of our 2019 PUD reserves to proved developed reserves. During 2019, we invested $399.5 million to develop and convert 66% of our 2018 PUD reserves to proved developed reserves. During 2018, we invested $264.5 million to develop and convert 30% of our 2017 PUD reserves to proved developed reserves.

During 2020, our 40.5 MMBOE of PUD reserve additions consisted of 33.8 MMBOE added in the Permian Basin and 6.7 MMBOE added in Mid-Continent. At December 31, 2020, 90% of our PUD reserves were in the Permian Basin, while the remainder were in our western Oklahoma Cana area. During 2020, we had net negative PUD reserve revisions of 14.0 MMBOE. Of this total, 10.0 MMBOE was for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure and the majority of the remainder was due to downward price revisions. We have no PUD reserves that have remained undeveloped for five years or more after initial disclosure and we have no PUD reserves whose scheduled development is beyond five years of initial disclosure.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Costs Incurred**—**The following table sets forth our costs incurred for property acquisition, exploration, and development activities.

	Years Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Acquisition of properties			
Proved	$ 11,878	$ 695,450	$ 62
Unproved	46,946	1,083,230	102,666
Exploration	1,522	2,321	6,341
Development	496,388	1,181,605	1,487,453
	$ 556,734	$ 2,962,606	$ 1,596,522

Aggregate Capitalized Costs**—**The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2020.

(in thousands)	**December 31, 2020**
Proved properties	$ 21,281,840
Unproved properties and properties under development, not being amortized	1,142,183
	22,424,023
Less—accumulated depreciation, depletion, amortization, and impairment	(18,987,354)
Net oil and gas properties	$ 3,436,669

Costs Not Being Amortized**—**The following table summarizes oil and gas property costs not being amortized at December 31, 2020, by year that the costs were incurred.

(in thousands)	**December 31, 2020**
2020	$ 197,861
2019	827,418
2018	65,770
2017 and prior	51,134
	$ 1,142,183

Of the costs not being amortized, $151.4 million (13%) relates to unevaluated wells in progress and $98.3 million (9%) is capitalized interest. The remaining $892.5 million (78%) is for land and seismic expenditures, most of which were for costs invested in Permian Basin ($852.6 million) and Mid-Continent ($39.3 million). The majority of the Permian Basin balance stems from the Resolute acquisition. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors. We expect to include these costs in the amortization computation as we continue with our exploration and development plans.

Oil and Gas Operations—The following table contains direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax expense related to our oil and gas operations is computed using the effective tax rate for the period, with the 2020 effective tax rate adjusted to remove the goodwill impairment not deductible for tax purposes and the change in valuation allowance.

	Years Ended December 31,		
(in thousands, except per BOE)	**2020**	**2019**	**2018**
Oil, gas, and NGL revenues from production	$ 1,512,688	$ 2,321,921	$ 2,297,645
Less operating costs and income taxes:			
Impairment of oil and gas properties	1,638,329	618,693	—
Depletion	625,481	817,099	538,919
Asset retirement obligation	14,653	8,586	7,142
Production	285,324	339,941	296,189
Transportation, processing, and other operating	213,366	238,259	211,463
Taxes other than income	79,699	148,953	125,169
Income tax (benefit) expense	(295,716)	26,318	252,840
	2,561,136	2,197,849	1,431,722
Results of operations from oil and gas producing activities	$ (1,048,448)	$ 124,072	$ 865,923
Depletion rate per BOE	$ 6.77	$ 8.04	$ 6.65

Standardized Measure of Future Net Cash Flows—The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ("Standardized Measure") is calculated in accordance with guidance provided by the FASB. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company's proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, varying price and cost assumptions, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are based upon the forecasted future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The following summary sets forth our Standardized Measure.

	December 31,		
(in thousands)	**2020**	**2019**	**2018**
Future cash inflows	$ 7,167,623	$ 11,726,488	$ 14,050,367
Future production costs	(3,193,242)	(4,619,438)	(4,889,601)
Future development costs	(525,714)	(814,397)	(1,017,318)
Future income tax expenses	(66,555)	(578,675)	(1,303,762)
Future net cash flows	3,382,112	5,713,978	6,839,686
10% annual discount for estimated timing of cash flows	(1,129,593)	(2,084,952)	(2,824,499)
Standardized measure of discounted future net cash flows	$ 2,252,519	$ 3,629,026	$ 4,015,187

The estimates of cash flows shown above are based upon the unweighted trailing twelve-month average first-day-of-the-month benchmark prices. See table above under ***Oil and Gas Reserve Information*** for prices used in determining the Standardized Measure. Prices are market driven and will fluctuate due to supply and demand factors, seasonality, and geopolitical, economic, and other factors.

The following are the principal sources of change in the Standardized Measure.

	Years Ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Standardized measure, beginning of period	$ 3,629,026	$ 4,015,187	$ 3,285,001
Sales, net of production costs	(934,299)	(1,594,768)	(1,660,649)
Net change in sales prices and in production costs related to future production	(1,465,206)	(1,267,223)	377,178
Extensions and discoveries, net of future production and development costs	261,090	758,685	1,738,993
Changes in estimated future development costs	130,440	35,940	194,523
Previously estimated development costs incurred during the period	306,225	640,292	335,954
Revisions of quantity estimates	(273,738)	(304,217)	96,783
Accretion of discount	394,835	473,919	372,482
Change in income taxes	283,764	404,681	(284,186)
Purchases of reserves in place	—	568,897	—
Sales of reserves in place	(3,838)	(18,330)	(300,592)
Change in production rates and other	(75,780)	(84,037)	(140,300)
Standardized measure, end of period	$ 2,252,519	$ 3,629,026	$ 4,015,187

CIMAREX ENERGY CO.

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

The tables below summarize our quarterly financial data for 2020 and 2019. The sum of the individual quarterly earnings (loss) per common share amounts may not agree with year-to-date earnings (loss) per common share amounts because each quarter's computation is based on the number of shares outstanding at the end of the applicable quarter using the two-class method.

	Quarter			
2020	**First**	**Second**	**Third**	**Fourth**
(in thousands, except per share data)				
Revenues	$ 472,830	$ 249,383	$ 401,659	$ 434,723
Expenses, net	1,247,112	1,174,530	694,399	410,012
Net (loss) income	$ (774,282)	$ (925,147)	$ (292,740)	$ 24,711
Earnings (loss) per share to common stockholders:				
Basic	$ (7.77)	$ (9.28)	$ (2.94)	$ 0.25
Diluted	$ (7.77)	$ (9.28)	$ (2.94)	$ 0.25

	Quarter			
2019	**First**	**Second**	**Third**	**Fourth**
(in thousands, except per share data)				
Revenues	$ 576,957	$ 546,463	$ 582,305	$ 657,244
Expenses, net	550,641	437,154	458,458	1,041,335
Net income (loss)	$ 26,316	$ 109,309	$ 123,847	$ (384,091)
Earnings (loss) per share to common stockholders:				
Basic	$ 0.26	$ 1.07	$ 1.21	$ (3.87)
Diluted	$ 0.26	$ 1.07	$ 1.21	$ (3.87)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), has evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended ("Exchange Act")) as of December 31, 2020. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods required by the U.S. Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including the CEO and CFO, to allow timely decisions regarding required disclosures.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Cimarex's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. The Company's internal control over financial reporting also includes those policies and procedures that:

(1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets;

(2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and directors; and

(3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the consolidated financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2020, Cimarex's management assessed the effectiveness of internal control over financial reporting based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that assessment, management concluded that the internal control over financial reporting was effective as of December 31, 2020.

The Company's independent registered public accounting firm, KPMG LLP, that audited the consolidated financial statements included in Item 8 of this Form 10-K has also audited the Company's internal control over financial reporting as of December 31, 2020 and has issued an attestation report. KPMG LLP's attestation report on the Company's internal control over financial reporting is included later in this Item 9A of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter ended December 31, 2020 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Cimarex Energy Co.:

Opinion on Internal Control Over Financial Reporting

We have audited Cimarex Energy Co. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements), and our report dated February 23, 2021 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Denver, Colorado
February 23, 2021

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning the directors of Cimarex required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2021 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2020. The executive officers of Cimarex as of February 23, 2021 were:

Name	Age	Office
Thomas E. Jorden	63	Chairman of the Board, Chief Executive Officer, and President
Stephen P. Bell	66	Executive Vice President — Business Development
G. Mark Burford	53	Senior Vice President and Chief Financial Officer
Francis B. Barron	58	Senior Vice President — General Counsel
John A. Lambuth	58	Executive Vice President — Exploration
Christopher H. Clason	54	Senior Vice President and Chief Human Resources Officer
Thomas F. McCoy	58	Senior Vice President — Production
Blake A. Sirgo	38	Vice President — Operations
Gary R. Abbott	48	Vice President — Corporate Engineering
Timothy A. Ficker	53	Vice President — Controller, Chief Accounting Officer, and Assistant Secretary

There are no family relationships by blood, marriage, or adoption among any of the above executive officers. All executive officers are elected annually by the board of directors to serve for one year or until a successor is elected and qualified. There is no arrangement or understanding between any of the officers and any other person pursuant to which the officer was selected as an executive officer.

THOMAS E. JORDEN was elected Chairman of the Board effective August 14, 2012 after being named President and Chief Executive Officer effective September 30, 2011. Since December 8, 2003, Mr. Jorden served as Executive Vice President of Exploration and had served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as Vice President of Exploration (October 1999 to September 2002) and Chief Geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

STEPHEN P. BELL was named Executive Vice President, Business Development effective September 13, 2012. Since September 2002, Mr. Bell served as Senior Vice President of Business Development and Land. Prior to its merger with Cimarex, Mr. Bell was with Key Production Company, Inc. since February 1994. In September 1999, he was appointed Senior Vice President, Business Development and Land. From February 1994 to September 1999, he served as Vice President, Land.

G. MARK BURFORD was named Senior Vice President and Chief Financial Officer in March 2019. Mr. Burford was appointed Vice President and Chief Financial Officer in September 2015 and Vice President, Capital Markets and Planning in December 2010. Mr. Burford joined Cimarex in April 2005 as Director of Capital Markets. Prior to joining Cimarex, he was Director of Investor Relations for Whiting Petroleum and Tom Brown. His experience also includes equity research with Petrie Parkman & Co., an investment banking firm, and public accounting.

FRANCIS B. BARRON joined Cimarex as Senior Vice President, General Counsel in July 2013. From February 2004 until July 2013, Mr. Barron served in various capacities at Bill Barrett Corporation, a publicly traded, Denver-based oil and gas exploration and development company, including as Executive Vice President, General Counsel, and Secretary. He also served as Chief Financial Officer from November 2006 until March 2007. Prior to February 2004, Mr. Barron was a partner at the Denver, Colorado office of the law firm of Patton Boggs LLP as well as a partner at Bearman Talesnick & Clowdus Professional Corporation. Mr. Barron’s practice included corporate, securities, and business law for publicly traded oil and gas companies.

JOHN A. LAMBUTH was named Executive Vice President of Exploration in February 2020. He served as Senior Vice President of Exploration from December 2015 until February 2020. He previously served as Vice President of Exploration beginning September 2012 and Chief Geophysicist, a position he held since joining Cimarex in 2004. Mr. Lambuth began his career in 1985 with Shell Oil Co., where he held various positions in exploration and in research and development. Immediately prior to joining Cimarex, he spent three years as onshore Exploration Manager of El Paso Energy Company.

CHRISTOPHER H. CLASON was named Senior Vice President and Chief Human Resources Officer in February 2020. Mr. Clason joined Cimarex as Vice President and Chief Human Resources Officer in April 2019. From February 2016 until April 2019, Mr. Clason was Director of MBA Career Management and Employer Relations at the Marriott School of Business at Brigham Young University. Prior to his work in higher education, he was Senior Vice President and Chief Human Resources Officer at ProBuild LLC, a Devonshire Investors company. From 2001 until 2014, Mr. Clason held various global HR executive leadership roles at Honeywell International, including Vice President Human Resources and Communications at Honeywell Aerospace. His background includes extensive international experience at Citigroup and early career work at Chevron.

THOMAS F. McCOY was named Senior Vice President of Production in February 2020. He previously served as Vice President of Production beginning in August 2013. He joined Cimarex as Gulf Coast Engineering Manager in 2003, and later served as Chief Reservoir Engineer and as Mid-Continent Exploration Manager. Prior to joining Cimarex, Mr. McCoy was with Vintage Petroleum Company and began his career in 1987 with Phillips Petroleum Company. Mr. McCoy holds a B.S. and M.S. in Petroleum Engineering from the University of Tulsa.

BLAKE A. SIRGO was named Vice President of Operations in February 2020. He previously served as Vice President Operations Resources from November 2018 to February 2020, Permian Division Production Manager from 2016 to November 2018, and in various engineering and production manager positions since joining Cimarex in 2008. Mr. Sirgo began his career in 2005 with Occidental Petroleum as a facilities engineer. Mr. Sirgo holds a Bachelor’s in Mechanical Engineering from the University of Texas.

GARY R. ABBOTT was named Vice President of Corporate Engineering March 1, 2005. Since January 2002, Mr. Abbott served as manager, Corporate Reservoir Engineering. From April 1999 to January 2002, Mr. Abbott was a senior engineer with Key Production Company, Inc.

TIMOTHY A. FICKER was appointed Vice President, Controller, Chief Accounting Officer, and Assistant Secretary in December 2016 to be effective in February 2017 and previously served as the Company’s Controller since September 2016. Prior to joining Cimarex, he was the Chief Financial Officer of Alcova Management LLC, Venoco, Inc., and Infinity Energy Resources Inc. Mr. Ficker previously served as an audit partner in KPMG LLP’s energy audit practice in Denver and as an audit partner for Arthur Andersen LLP, where he served clients primarily in the energy industry.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2021 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2020.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the company at December 31, 2020:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	547,377	$ 68.94	1,674,858
Equity compensation plans not approved by security holders	—	—	—
Total	547,377	$ 68.94	1,674,858

The remaining information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2021 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2020.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2021 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2020.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2021 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2020.

PART IV

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated. All management contracts or compensatory plans or arrangements are designated by a plus sign (+).

Exhibit	Title
2.1	Agreement and Plan of Merger dated as of November 18, 2018, by and among Cimarex Energy Co., CR Sub 1 Inc., CR Sub 2 LLC and Resolute Energy Corporation (filed as Exhibit 2.1 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (Commission File No. 001-31446) dated June 7, 2005 and incorporated herein by reference).
3.2	Amended and Restated By-laws of Cimarex Energy Co. dated November 11, 2015 (filed as Exhibits 3.1 and 3.2 to the Current Report on Form 8-K filed on November 12, 2015 (Commission File No. 001-31446) and incorporated herein by reference).
4.1	Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012 (Registration No. 333-183939) and incorporated herein by reference).
4.2	Debt Securities Indenture dated as of April 5, 2012, by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2012 (Commission File No. 001-31446) and incorporated herein by reference.
4.3	First Supplemental Indenture dated as of April 5, 2012, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 5, 2012 (Commission File No. 001-31446) and incorporated herein by reference.

Exhibit	Title
4.4	Form of 5.875% Senior Notes due 2022 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 5, 2012 (Commission File No. 001-31446) and incorporated herein by reference.
4.5	Indenture dated as of June 4, 2014, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 4, 2014 (Commission File No. 001-31446) and incorporated herein by reference.
4.6	First Supplemental Indenture dated as of June 4, 2014, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on June 4, 2014 (Commission File No. 001-31446) and incorporated herein by reference.
4.7	Form of 4.375% Senior Notes due 2024 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on June 4, 2014 (Commission File No. 001-31446) and incorporated herein by reference.
4.8	Form of Indenture by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee (filed as Exhibit 4.7 to Registration Statement on Form S-3 filed September 21, 2015 (Registration No. 333-183939) and incorporated herein by reference).
4.9	Indenture dated as of April 10, 2017, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 10, 2017 (Commission File No. 001-31446) and incorporated herein by reference.
4.10	First Supplemental Indenture dated as of April 10, 2017, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 10, 2017 (Commission File No. 001-31446) and incorporated herein by reference.
4.11	Form of 3.90% Senior Notes due 2027 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 10, 2017 (Commission File No. 001-31446) and incorporated herein by reference.
4.12	Certificate of Designations of 8⅛% Series A Cumulative Perpetual Convertible Preferred Stock of Cimarex Energy Co., dated February 28, 2019 (filed on March 1, 2019 as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).
4.13	Second Supplemental Indenture dated as of March 8, 2019, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee (filed on March 8, 2019 as Exhibit 4.2 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).
4.14	Form of 4.375% Senior Notes due 2029 (filed on March 8, 2019 as Exhibit 4.3 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).
4.15	Description of Registrant's Securities *
10.1	Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lenders filed on July 18, 2011 (Commission File No. 001-31446) as Exhibit 10.l to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

Exhibit	Title
10.2	First Amendment to Credit Agreement dated as of July 19, 2012, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 (Commission File No. 001-31446) as Exhibit 10.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
10.3	Second Amendment to Credit Agreement dated as of May 1, 2014, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 (Commission File No. 001-31446) as Exhibit 10.2 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
10.4	Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). +
10.5	2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference). +
10.6	Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference). +
10.7	Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference). +
10.8	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference). +
10.9	Form of Notice of Grant and Award Agreement (Other Stock Award with performance conditions) (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference). +
10.10	2014 Equity Incentive Plan adopted May 15, 2014 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on April 1, 2014 (Commission File No. 001-31446) and incorporated herein by reference. +
10.11	Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference). +
10.12	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference). +
10.13	Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference). +

Exhibit	Title
10.14	Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference). +
10.15	Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2014 filed on February 25, 2015 (Commission File No. 001-31446) and incorporated herein by reference). +
10.16	Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). +
10.17	Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). +
10.18	Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005, amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference). +
10.19	Amendment to Cimarex Energy Co. Change in Control Severance Plan dated effective March 19, 2013 (filed as Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013 (Commission File No. 001-31446) and incorporated herein by reference). +
10.20	Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2012 filed on February 26, 2013 (Commission File No. 001-31446) and incorporated herein by reference). +
10.21	Credit Agreement Dated as of October 16, 2015, by and among Cimarex, the Administrative Agent, the Syndication Agent, the Documentation Agents, and the Lenders (filed on October 19, 2015 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).
10.22	Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.2 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 2, 2015 and incorporated herein by reference). +
10.23	Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on August 9, 2017 (Commission File No. 001-31446) and incorporated herein by reference). +
10.24	Purchase and Sale Agreement dated May 23, 2018 between Cimarex Energy Co., Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. (collectively, as "Seller") and Callon Petroleum Operating Company as Buyer (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 24, 2018 (Commission File No. 001-31446) and incorporated herein by reference).

Exhibit	Title
10.25	Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.35 to the Annual Report on Form 10-K for the year ended December 31, 2018 filed on February 20, 2019 (Commission File No. 001-31446) and incorporated herein by reference). +
10.26	Amended and Restated Credit Agreement Dated as of February 5, 2019, by and among Cimarex, as Borrower, the Administrative Agent, the Syndication Agent, the Co-Documentation Agents, the Lenders, and the Lead Arrangers and Bookrunners (filed on February 7, 2019 as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).
10.27	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co. and Monarch Alternative Capital LP, MDRA GP LP and Monarch GP LLC (filed as Exhibit 10.1 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.28	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co., John C. Goff and certain other related entities thereto (filed as Exhibit 10.2 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.29	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co. and RR Advisors, LLC (filed as Exhibit 10.3 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.30	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co. and Richard Betz (filed as Exhibit 10.4 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.31	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co. and Nicholas J. Sutton (filed as Exhibit 10.5 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.32	Voting Agreement, dated as of November 18, 2018, by and among Cimarex Energy Co. and Theodore Gazulis (filed as Exhibit 10.6 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 20, 2018 and incorporated herein by reference).
10.33	Amended and Restated Credit Agreement, dated February 5, 2019, among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, Wells Fargo Bank, N.A., as syndication agent, the co-documentation agents party thereto, J.P. Morgan Chase Bank, N.A. and Wells Fargo Securities, LLC, as lead arrangers and bookrunners, and the lenders party thereto. (filed as Exhibit 10.1 to the Current Report on Form 8-K filed February 7, 2019 (Commission File No. 001-31446) and incorporated herein by reference).
10.34	Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed on May 29, 2019 as Exhibit 10.2 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference). +
10.35	2019 Equity Incentive Plan (filed on May 30, 2019 as Exhibit 99.1 to the Registration Statement on Form S-8 (Commission File No. 001-31446) and incorporated herein by reference). +
10.36	Form of Notice of Grant of Restricted Stock and Award Agreement (filed on August 5, 2019 as Exhibit 10.4 to the Quarterly Report on Form 10-Q (Commission File No. 001-31446) and incorporated herein by reference). +

Exhibit	Title
10.37	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed on August 5, 2019 as Exhibit 10.5 to the Quarterly Report on Form 10-Q (Commission File No. 001-31446) and incorporated herein by reference). +
10.38	Director Emeritus Agreement dated September 30, 2019 between Cimarex Energy Co. and Michael J. Sullivan (filed on September 23, 2019 as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference). +
10.39	Form of Severance Compensation Agreement (filed as Exhibit 10.1 to the Current Report on Form 8-K filed March 13, 2020 (Commission File No. 001-31446) and incorporated herein by reference). +
10.40	Form of Notice of Grant of Performance Stock Units and Award Agreement (Performance Award) (filed as Exhibit 10.2 to the Current Report on Form 8-K filed March 13, 2020 (Commission File No. 001-31446) and incorporated herein by reference). +
10.41	Form of Amendment to Severance Compensation Agreement (filed as Exhibit 10.2 to the Current Report on Form 8-K/A filed May 12, 2020 (Commission File No. 001-31446) and incorporated herein by reference). +
10.42	First Amendment to Amended and Restated Credit Agreement, dated June 3, 2020, among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, Wells Fargo Bank, N.A., as syndication agent, the co-documentation agents party thereto, J.P. Morgan Chase Bank, N.A. and Wells Fargo Securities, LLC, as lead arrangers and bookrunners, and the lenders party thereto. (filed as Exhibit 10.1 to the Current Report on Form 8-K/A filed June 4, 2020 (Commission File No. 001-31446) and incorporated herein by reference).
10.43	Succession Agreement dated July 1, 2020 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.1 to the Current Report on Form 8-K/A filed July 2, 2020 (Commission File No. 001-31446) and incorporated herein by reference). +
10.44	Form of Notice of Grant of Performance Stock Units and Award Agreement (Performance Award). + *
14.1	Revised Code of Business Conduct and Ethics for Directors, Officers, and Employees dated August 30, 2016 (filed as Exhibit 14.1 and 14.2 to the Current Report on Form 8-K filed September 1, 2016 (Commission File No. 001-31446) and incorporated herein by reference).
21.1	Significant subsidiaries of the Registrant. *
23.1	Consent of KPMG LLP. *
23.2	Consent of DeGolyer and MacNaughton. *
24.1	Power of Attorney of directors of the Registrant. *
31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *

Exhibit	Title
31.2	Certification of G. Mark Burford, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
32.2	Certification of G. Mark Burford, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
99.1	Letter dated January 20, 2021 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2020 of certain selected properties. *
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 23, 2021

CIMAREX ENERGY CO.

By: /s/ Thomas E. Jorden

Thomas E. Jorden
Chairman of the Board, Chief Executive Officer, and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Thomas E. Jorden Thomas E. Jorden	Chairman of the Board, Director, Chief Executive Officer, and President (Principal Executive Officer)	February 23, 2021
/s/ G. Mark Burford G. Mark Burford	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2021
/s/ Timothy A. Ficker Timothy A. Ficker	Vice President, Controller, Chief Accounting Officer (Principal Accounting Officer)	February 23, 2021
* *Attorney-in-Fact* Joseph R. Albi	Director	February 23, 2021
* *Attorney-in-Fact* Paul N. Eckley	Director	February 23, 2021
* *Attorney-in-Fact* Hans Helmerich	Director	February 23, 2021
* *Attorney-in-Fact* Kathleen A. Hogenson	Director	February 23, 2021
* *Attorney-in-Fact* Harold R. Logan, Jr.	Director	February 23, 2021
* *Attorney-in-Fact* Floyd R. Price	Director	February 23, 2021
* *Attorney-in-Fact* Monroe W. Robertson	Director	February 23, 2021
* *Attorney-in-Fact* Lisa A. Stewart	Director	February 23, 2021
* *Attorney-in-Fact* Frances M. Vallejo	Director	February 23, 2021
*By: /s/ G. Mark Burford G. Mark Burford *Attorney-in-Fact*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2021