Contango

OIL AND GAS COMPANY

Forward Together

2020 Annual Report

Contango is a platform used to **acquire, produce, develop, and manage** domestic oil and gas assets. We operate in a manner that prioritizes the **safety** of our employees and the **environment.** We seek to be among the **lowest cost operators** in the industry & to do so while maintaining financial discipline. Our **goal is to continue to grow** our organization, and the value of the organization, in a disciplined fashion through the hard work and contribution from our **talented employee base** and the continued **support of our lenders and shareholders,** *thereby - Forward Together!*

Fellow Shareholders,

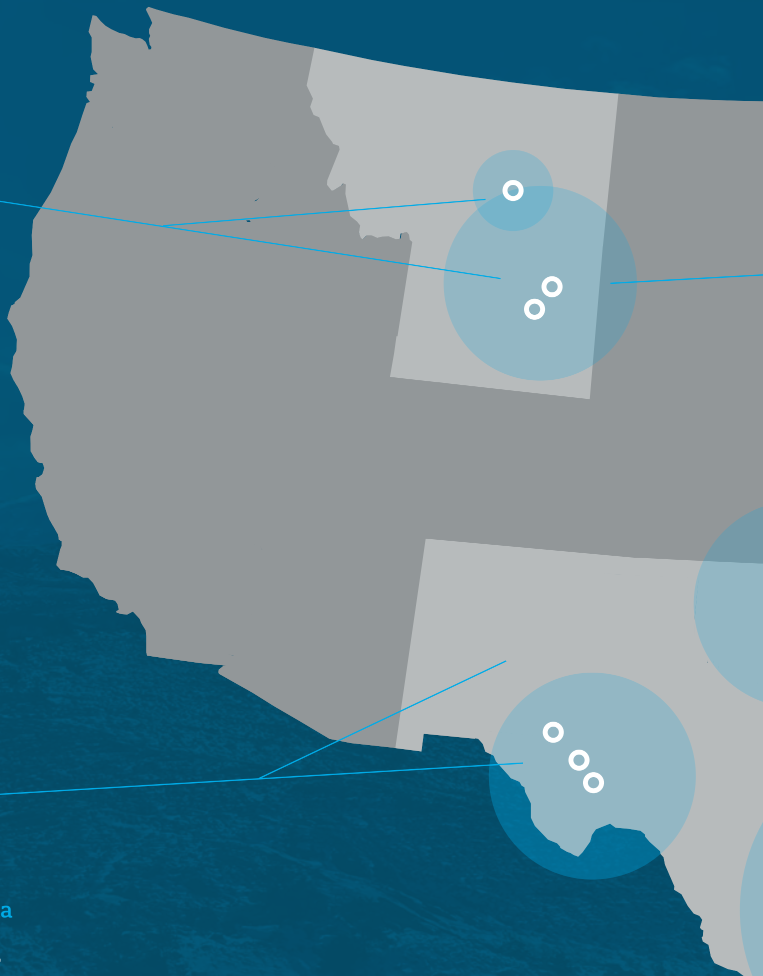
The upstream sector of the energy industry faced a myriad of domestic and global challenges during 2020 that resulted in a significant contraction in the sector, including a much lower and unstable commodity price environment, declines in U.S drilling activity, production and jobs and the evaporation of needed debt and equity capital available to the industry. The most significant of those challenges surfaced concurrently during the first quarter of 2020 and persisted throughout the year. During the first quarter, the COVID-19 virus surfaced and quickly consumed all aspects of society, including a disruption in the ability to maintain a safe, coordinated and collaborative workplace, thereby leading to our team having to learn how to work from home; then came a material reduction in the demand for oil and natural gas resulting from the COVID-related shutdown in the domestic and worldwide economies and the simultaneous inability of Russia and OPEC (Saudi Arabia) to agree on oil production quotas, which combined, resulted in a flooding of world markets with excess crude causing a dramatic decline in crude oil and natural gas prices that has been the norm for most of 2020. While most of the energy industry struggled to survive during this period, through the dedication, commitment, and efforts of our team, including the support of our lenders and shareholders, we were able to take advantage of the challenging economic environment, and unlike most of our industry competitors, were successful at dramatically increasing the size of the Company and market equity capitalization through identifying and negotiating two material, strategic acquisitions on very attractive economics that we closed in the first month of 2021. Due to the uncertain outlook in an unstable commodity price environment, we also discontinued all drilling activity and focused on cutting costs in the office and field and paying down debt to enhance our ability to quickly react to acquisition of PDP-heavy opportunities. The cost reductions accomplished in the field were instrumental in increasing the value of our existing reserves and improving our cash flow. Lastly, as we worked through finalizing our due diligence and integration planning for the recently closed acquisitions, our technical teams were very successful at developing a plan to immediately improve the cost structure on the assets acquired, which then provided post-close increases in the value of those acquired reserves and the cash margin expected to be generated from those reserves in 2021 and beyond. As we approached year end, and in contemplation of the acquisition closings, we used those acquisitions to opportunistically attract new equity investors to complement new common equity investment by our existing shareholders. That equity support and stock value appreciation, combined with the expansion of our bank credit facility, has enhanced our liquidity and acquisition currency in a material way. Our expanded financial liquidity, higher cash flow, and lower debt profile provide us with a very strong foundation and competitive advantage when pursuing our industry consolidation strategy, i.e. vs. our peers, by being the preferred option for distressed and non-natural owners of quality assets in divestiture processes. The combination of our strong and flexible financial profile, our scale, and our market visibility and reputation for being able to quickly close transactions, also makes Contango an excellent option for industry-fatigued owners of private companies to combine their portfolio companies with a viable, growing public company. While we are not fully beyond the domestic and global pandemic risk, or the global socio-economic factors that we continue to face today, and which are beyond our control, we will continue to adapt to the current environment, and develop, implement, and pursue a business strategy that minimizes their impact on our operations and results, and also gives us a platform from which we hope to capitalize on opportunities where industry peers don't have the stamina or flexibility to address and overcome those challenges. As we move through 2021 we will continue to stick to our core competencies that have allowed us to succeed over the last two difficult years in our industry, i.e. to pursue a consolidator strategy for as long as that window remains open, to continue to focus on cost reduction to become the low-cost operator, to execute on our low risk, high multiple on investment organic capital programs, to maintain a strong financial profile, and when deemed appropriate, allocate a prudent amount of free cash flow to higher risk, but high return, development and exploratory drilling programs.

In conclusion, we are proud of, and excited about, our recent successes, but we are not going to sit back and rest on those accomplishments. Our team is committed to the task of continuing to be aggressive at taking advantage of acquisition opportunities and utilizing our technical teams to improve the economics of assets acquired even more after close, and, with the ongoing support of our lenders and shareholders, we look forward to creating meaningful value for the benefit of all Contango stakeholders, i.e. *Forward Together.*

Wilkie S. Colyer
Chief Executive Officer

2020 Contango Total*

	2020	Pro Forma 2020***
Acreage (Gross)	1,023,265	1,585,025
Acreage (Net)	472,576	829,921
SEC PV10 (Millions)	$ 126.4	$ 363.8
2020 Production (MMBOE)	6.1	9.9
Total Proved Reserves (MMBOE)	34.3	71.6
Total Proved Reserves (% Developed)	80%	86%
Total Proved Reserves (% Liquids)	59%	74%



Rockies

WYOMING, MONTANA

	2020	Pro Forma 2020***
Acreage (Gross)	33,200	304,643
Acreage (Net)	23,000	212,105
SEC PV10 (Millions)	$ 0.6	$ 145.0
2020 Production (MMBOE)	0.1	1.6
Total Proved Reserves (MMBOE)	0.1	18.1
Total Proved Reserves (% Developed)	100%	90%
Total Proved Reserves (% Liquids)	91%	84%

Permian Basin

WEST TEXAS, NEW MEXICO

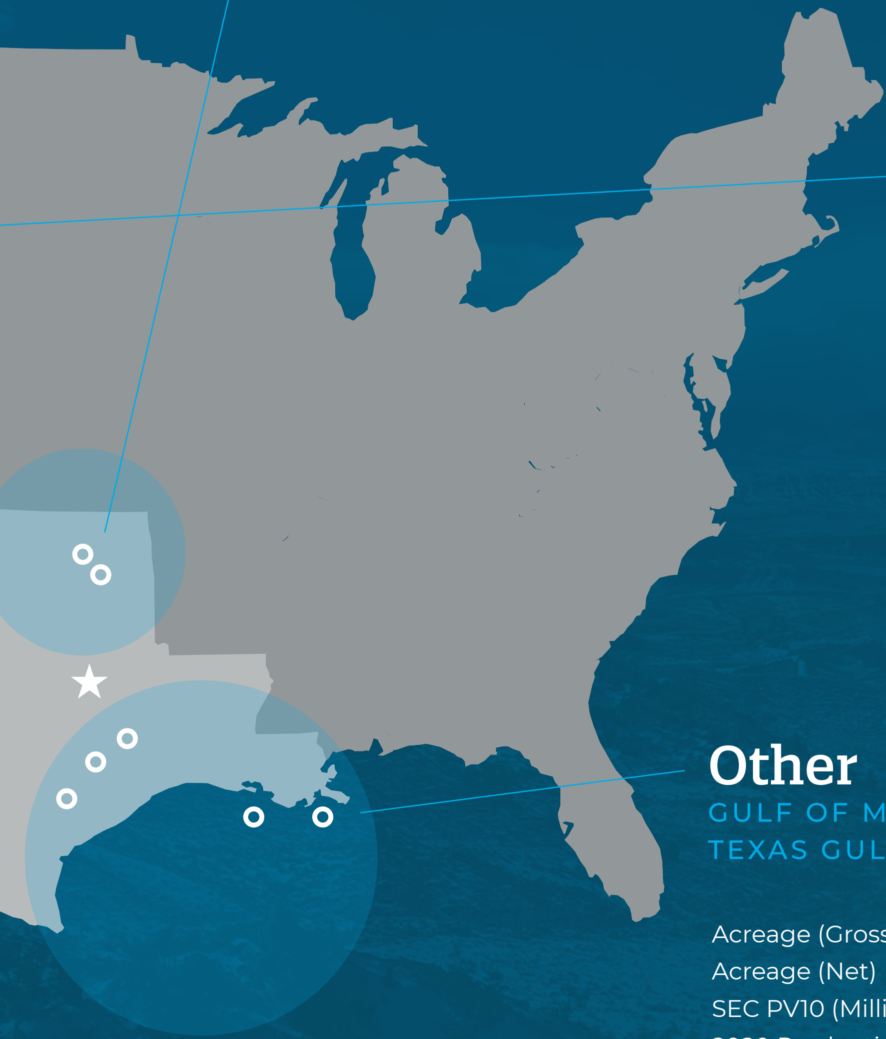
	2020	Pro Forma 2020***
Acreage (Gross)	16,248	212,097
Acreage (Net)	7,512	107,364
SEC PV10 (Millions)	$ 34.4	$ 52.3
2020 Production (MMBOE)	0.4	1.8
Total Proved Reserves (MMBOE)	8.3	14.7
Total Proved Reserves (% Developed)	22%	56%
Total Proved Reserves (% Liquids)	92%	86%

* Total does not include EXARO

Midcontinent

OKLAHOMA

	2020	Pro Forma 2020***
Acreage (Gross)	903,710	998,178
Acreage (Net)	402,155	470,543
SEC PV10 (Millions)	$ 75.3	$ 151.0
2020 Production (MMBOE)	4.3	5.2
Total Proved Reserves (MMBOE)	20.4	33.3
Total Proved Reserves (% Developed)	99%	94%
Total Proved Reserves (% Liquids)	52%	70%



Exaro**

WYOMING

	2020
Acreage (Gross)	2,131
Acreage (Net)	385
SEC PV10 (Millions)	$ 14.2
2020 Production (MMBOE)	1
Total Proved Reserves (MMBOE)	2.6
Total Proved Reserves (% Developed)	100%
Total Proved Reserves (% Liquids)	6%

Other

GULF OF MEXICO, LOUISIANA, MISSISSIPPI, TEXAS GULF COAST

	2020	Pro Forma 2020***
Acreage (Gross)	70,107	70,107
Acreage (Net)	39,909	39,909
SEC PV10 (Millions)	$ 15.5	$ 15.5
2020 Production (MMBOE)	1.3	1.3
Total Proved Reserves (MMBOE)	5.5	5.5
Total Proved Reserves (% Developed)	100%	100%
Total Proved Reserves (% Liquids)	27%	27%

** Net to MCF 37% equity interest

*** Assumes Mid-Con and Silvertip Acquisitions occured on January 1, 2020

	2020	2019	2018
Proved Reserves (1):			
Crude Oil (MBbls)	13,004	19,085	9,434
Natural Gas (Mmcf)	84,482	131,300	54,206
Natural Gas Liquids (MBbls)	7,154	11,764	3,517
Barrels of Oil Equivalent (Mboe)	34,238	52,731	21,985
Future Net Revenue From Proved Reserves (1):			
Undiscounted before income taxes ($000)	$ 189,702	$ 476,156	$ 413,864
Discounted at 10% after income taxes ($000)	$ 115,587	$ 257,842	$ 218,944
Production (Net Sales Volume)			
Crude Oil (MBbls)	1,674	791	569
Natural Gas (Mmcf)	18,967	9,523	9,779
Natural Gas Liquids (MBbls)	1,262	612	474
Barrels of Oil Equivalent (Mboe)	6,097	2,990	2,673
Average Prices For The Year (1):			
Crude Oil ($/Bbl)	$ 37.31	$ 56.55	$ 60.43
Natural Gas ($/Mcf)	$ 1.65	$ 2.35	$ 3.05
Natural Gas Liquids ($/Bbl)	$ 13.54	$ 15.39	$ 27.04
Weighted Average Equivalent Sales Price ($/BOE)	$ 18.19	$ 25.59	$ 28.82
Prices Used For Year-End Reserves:			
Crude Oil ($/Bbl)	$ 36.57	$ 53.98	$ 62.90
Natural Gas ($/Mcf)	$ 1.86	$ 2.17	$ 3.02
Natural Gas Liquids ($/Bbl)	$ 12,43	$ 16.95	$ 27.89
Total Revenues ($000)	$ 112,920	$ 76,512	$ 77,087
Total Expenses ($000)			
Lease Operating Expenses and Production Taxes	$ (72,847)	$ (33,205)	$ (25,552)
Exploration Expenses	$ (11,594)	$ (1,003)	$ (1,637)
DD&A and Impairment	$ (198,834)	$ (168,097)	$ (145,389)
G&A	$ (24,940)	$ (24,938)	$ (24,157)
Gain (Loss) on Derivatives	$ 27,585	$ (3,357)	$ 1,939
Other Income (Expenses)	$ 3,115	$ (5,488)	$ (3,739)
Income (Loss) from Continuing Operations Before Taxes	$ (164,595)	$ (159,576)	$ (121,448)
Income Tax (Expense) Benefit	$ (747)	$ (220)	$ (120)
Net Income (Loss) from Continuing Operations	$ (165,342)	$ (159,796)	$ (121,568)
Net Income (Loss) From Continuing Operations Per Share (Dollars)			
Basic	$ (1.20)	$ (2.95)	$ (4.69)
Diluted	$ (1.20)	$ (2.95)	$ (4.69)
Weighted Average Shares Outstanding (000'S)			
Basic	$ 137,522	$ 54,136	$ 25,945
Diluted	$ 137,522	$ 54,136	$ 25,945
Total Assets ($000)	$ 170,267	$ 353,826	$ 257,132
Long-Term Debt, Including Current Portion ($000)	$ 12,369	$ 72,768	$ 60,000
Shareholders' Equity ($000)	$ 15,567	$ 116,040	$ 140,389

(1) SEC Pricing at 12/31/2020

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

☐ **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 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

Texas	**95-4079863**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

111 E. 5th Street, Suite 300
Fort Worth, Texas 76102
(Address of principal executive offices)

(817) 529-0059
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, Par Value $0.04 per share	MCF	NYSE American

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, 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 Exchange Act). Yes ☐ No ☒

At June 30, 2020, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE American) was $159.2 million. As of March 5, 2021, there were 199,146,980 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been omitted from this report since the registrant will file with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, a definitive proxy statement, pursuant to Regulation 14A. The information required by Items 10, 11, 12, 13 and 14 of this report, which will appear in the definitive proxy statement, is incorporated by reference into this Form 10-K.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2020
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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should", "could", "may", "will", "believe", "plan", "intend", "expect", "potential", "possible", "anticipate", "estimate", "forecast", "view", "efforts", "goal" and similar expressions identify forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in this report and those factors summarized below:

- volatility and significant declines in oil, natural gas and natural gas liquids prices, including regional differentials;
- any reduction in our borrowing base from time to time and our ability to repay any excess borrowings as a result of any such reduction;
- the impact of the COVID-19 pandemic, including reduced demand for oil and natural gas, economic slowdown, governmental and societal actions taken in response to the COVID-19 pandemic, stay-at-home orders, and interruptions to our operations;
- our ability to execute our corporate strategy of offering a "fee for service" property management service for oil and natural gas companies;
- risks related to our recent acquisition of producing oil and natural gas properties in the Big Horn Basin in Wyoming and Montana, Powder River Basin in Wyoming and Permian Basin in Texas and New Mexico from a private seller (the "Silvertip Acquisition"), and our acquisition via merger of Mid-Con Energy Partners, LP, (NASDAQ: MCEP) ("Mid-Con" and such acquisition, the "Mid-Con Acquisition"), including the risk that our and Silvertip and Mid-Con businesses will not be integrated successfully, that the anticipated cost savings, synergies and growth from those acquisitions may not be fully realized or may take longer to realize than expected, and that management attention will be diverted to integration-related issues;
- the effect of the Silvertip Acquisition and Mid-Con Acquisition on our stock price;
- the impact of the climate change initiative by President Biden's administration and Congress, including the January 2021 executive order imposing a moratorium on new oil and natural gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and natural gas permitting and leasing practices;
- our financial position;
- the potential impact of our derivative instruments;
- our business strategy, including our ability to successfully execute on our consolidation strategy or make any desired changes in our strategy from time to time;
- meeting our forecasts and budgets, including our 2021 capital expenditure budget;
- expectations regarding oil and natural gas markets in the United States and our realized prices;
- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations to agree to, adhere to and maintain oil prices and production controls;
- outbreaks and pandemics, even outside of our areas of operation, including COVID-19;

- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin and the Mid-continent area of Oklahoma, and realize the benefits associated therewith;
- increased costs and risks associated with our exploration and development in the Gulf of Mexico;
- the risks associated with acting as operator of deep high pressure and high temperature wells, including well blowouts and explosions, onshore and offshore;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of oil and natural gas wells;
- the concentration of drilling in the Southern Delaware Basin, including lower than expected production attributable to down spacing of wells;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, fund our drilling program and support our acquisition efforts;
- the cost and availability of rigs and other materials, services and operating equipment;
- timely and full receipt of sales proceeds from the sale of our production;
- our ability to find, acquire, market, develop and produce new oil and natural gas properties;
- the conditions of the capital markets and our ability to access debt and equity capital markets or other non-bank sources of financing, and actions by current and potential sources of capital, including lenders;
- interest rate volatility;
- our ability to complete strategic dispositions or acquisitions of assets or businesses and realize the benefits of such dispositions or acquisitions;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- the need to take impairments on our properties due to lower commodity prices or other changes in the value of our assets, which results in a non-cash charge to earnings;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- operating hazards attendant to the oil and natural gas business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures and other risks;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to retain key members of senior management and key technical employees and to find and retain skilled personnel;

- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- the uncertain impact of supply of and demand for oil, natural gas and NGLs;
- our ability to obtain goods and services critical to the operation of our properties;
- worldwide and United States economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our oil and natural gas discoveries;
- expanded rigorous monitoring and testing requirements;
- the ability to obtain adequate insurance coverage on commercially reasonable terms; and
- the limited trading volume of our common stock and general market volatility.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. Moreover, the effects of the COVID-19 pandemic may give rise to risks that are currently unknown or amplify the risks associated with many of the factors summarized above. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. You should not place undue reliance on forward-looking statements in this report as they speak only as of the date of this report.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and natural gas liquids that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and natural gas liquids that are ultimately recovered.

All forward-looking statements, expressed or implied, in this report are expressly 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 we or any person acting on our behalf may issue.

Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All references in this Form 10-K to the "Company", "Contango", "we", "us" or "our" are to Contango Oil & Gas Company and its wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-K relating to oil and natural gas reserves and the estimated future net cash flows attributable to those reserves, is based on estimates prepared by independent, third-party engineers, and is net to our interest.

Summary of Risks Associated with our Business

An investment in the Company is subject to risks inherent to our business. In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the risks and uncertainties described in in the section entitled

"Risk Factors" included in this report when evaluating the Company. Below is a summary of some of the risks we face, all of which are more fully described in Part I, Item 1A. "Risk Factors" below.

- The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our business, financial position, results of operations, and/or cash flows will depend on future developments, which are highly uncertain and cannot be predicted.

- We have no ability to control the market price for oil, natural gas and NGLs. Oil, natural gas and NGL prices fluctuate widely, and a continued substantial or extended decline in oil and natural gas prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on our business, results of operations and financial condition.

- Part of our strategy involves drilling in new or emerging plays, and a reduction in our drilling program may affect our revenues and access to capital.

- The reduction in the borrowing base under our Credit Agreement, and any further reductions as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

- If we are unable to comply with restrictions and covenants in our Credit Agreement, there could be a default under the terms of the agreement, which could result in an acceleration of payments of funds that we have borrowed.

- Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and/or a decline in our oil, natural gas and NGL reserves.

- We rely on third-party contract operators to drill, complete and manage some of our wells, production platforms, pipelines and processing facilities and, as a result, we have limited control over the daily operations of such equipment and facilities.

- Oil and natural gas reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

- The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

- Drilling for and producing oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

- The potential lack of availability of, or cost of, drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

- If prices of oil, natural gas and NGLs decline, we may incur further impairment of proved properties and experience a reduction in our proved undeveloped reserves.

- Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

- Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC or the FTC, we could be subject to substantial penalties and fines.

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

- We may not be able to utilize a portion of our net operating loss carryforwards (“NOLs”) to offset future taxable income for U.S. federal income tax purposes, which could adversely affect our net income and cash flows.

- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as activities related to fossil fuel extraction on federal properties, generally, and governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

- We may be subject to additional supplemental bonding under the BOEM financial assurance requirements.

- The BSEE has implemented stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

- We may be unable to integrate the business of Mid-Con Energy Partners, LP successfully or realize the anticipated benefits of the merger.

- Our bylaws provide certain limitations with respect to business combinations with affiliated stockholders, which may discourage transactions that would otherwise be preferred by a stockholder.

PART I

Item 1. *Business*

Overview

We are a Fort Worth, Texas based independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore properties primarily located in Oklahoma, Texas, Wyoming and Louisiana and use that cash flow to explore, develop, exploit and acquire oil and natural gas properties across the United States. We were originally formed in 1999 as a Nevada corporation and changed our state of incorporation to the State of Delaware in 2000, and, following approval by our stockholders in 2019, we changed our state of incorporation from the State of Delaware to the State of Texas.

The following table lists our primary producing areas as of December 31, 2020:

Location	Formation
Offshore Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Central Oklahoma	Mississippian, Woodford, Oswego, Cottage Grove, Chester, Cleveland and Red Fork
Western Anadarko	Tonkawa, Cottage Grove, Cleveland, Marmaton, Chase Sandstone, Morrow, Chester and Oswego
West Texas	Wolfcamp A and B
Other Onshore (TX, LA, WY)	Woodbine, Lewisville, Buda, Georgetown, Eagleford, and Muddy Sandstone

Impact of the COVID-19 Pandemic

A novel strain of the coronavirus ("COVID-19") surfaced in late 2019 and has spread, and continues to spread, around the world, including to the United States. In March 2020, the World Health Organization declared COVID-19 a pandemic, and the President of the United States declared the COVID-19 pandemic a national emergency. The COVID-19 pandemic has significantly affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the COVID-19 pandemic has resulted in travel restrictions, business closures and other restrictions that have disrupted the demand for oil throughout the world and, when combined with the oil supply increase attributable to the battle for market share among OPEC, Russia and other oil producing nations, resulted in oil prices declining significantly beginning in late February 2020. While there has been a modest recovery in oil prices, the length of this demand disruption is unknown, and there is significant uncertainty regarding the long-term impact to global oil demand, which has negatively impacted the Company's results of operations and planned 2020 capital activities. Due to the extreme volatility in oil prices and the impact of the COVID-19 pandemic on the financial condition of our upstream peers, we suspended our drilling program in the Southern Delaware Basin in the first quarter of 2020 and focused on certain measures that included, but were not limited to, the following:

- work from home initiatives for all but critical staff and the implementation of social distancing measures;
- a company-wide effort to cut costs throughout the Company's operations;
- utilization of the Company's available storage capacity to temporarily store a portion of its production for later sale at higher prices when advantageous to do so (such as the approximate 50,000 barrels of second quarter 2020 oil production we stored and sold during the third quarter of 2020 at higher oil prices);
- suspension of any further plans for operated onshore and offshore drilling in 2020;
- pursuit of additional "fee for service" opportunities similar to the Management Services Agreement entered into in June 2020 with Mid-Con Energy Partners LP ("Mid-Con") (NASDAQ: MCEP), which was terminated at the closing of the Mid-Con Acquisition (as defined below) between the Company and Mid-Con on January 21, 2021; and
- potential acquisitions of PDP-heavy assets, with attractive, discounted valuations, in stressed/distressed scenarios or from non-industry owners, such as our Silvertip Acquisition.

From our initial entry into the Southern Delaware Basin in 2016 and through early 2019, we focused on the development of our initial 6,500 net acre position in Pecos County, Texas ("Bullseye"), and in December 2018, we purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of our Bullseye acreage ("NE Bullseye") for approximately $7.5 million. We paid $3.2 million cash in

December 2018, with the remaining cash balance paid in installments in March and October of 2019. Our 2019 drilling program in West Texas included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. In December 2019, we began completion operations on the fourth NE Bullseye well, which began producing in January 2020. As of December 31, 2020, we were producing from 18 wells over our approximate 16,200 gross (7,500 net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations.

In response to low commodity prices, and a related window of opportunity to acquire producing properties on very attractive terms, we concluded our 2019 drilling program, which was designed to only preserve core areas of our West Texas play. Thereafter, we focused on identifying, evaluating and acquiring producing reserves. As a result, we were successful in closing the Will Energy Corporation ("Will Energy") and White Star Petroleum, LLC and certain of its affiliates (collectively, "White Star") acquisitions ("Will Energy Acquisition" and "White Star Acquisition") in the fourth quarter of 2019. These transactions were transformative, as production from these acquisitions represented approximately 70% of the Company's total net production for the year ended December 31, 2020. See Note 4 – "Acquisitions and Dispositions" for more information.

In connection with the September 2019 signing of the agreement to acquire certain assets from Will Energy and a concurrent equity offering, we entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the "Credit Agreement"). In connection with the entry into the Credit Agreement, we repaid all obligations outstanding on, and terminated, our previous credit agreement with Royal Bank of Canada, which matured on October 1, 2019. The Credit Agreement has since been amended to increase the number of lenders from three to nine, and among other things, to adjust the borrowing base to $130.0 million on January 21, 2021 and $120.0 million on March 31, 2021. See Note 13 – "Long-Term Debt" for more information.

In December 2019, we entered into a Joint Development Agreement with Juneau Oil & Gas, LLC ("Juneau"), which provides us the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. The first such exploratory prospect acquired by the Company, located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline, was determined to be unsuccessful in June 2020. We are currently evaluating for future testing a number of exploratory prospects included in the Joint Development Agreement, including our Boss Hogg prospect located in the Eugene Island 298 Area in the shallow waters off of the Louisiana coastline. Our strategy and timing on the testing of the Boss Hogg will be determined during the year based on regulatory considerations, some of which are fluid at this time, and on operational considerations, including the availability of appropriate equipment.

Subsequent to the reduction in our drilling program in the latter half of 2019, which then led to the suspension of onshore drilling in the first quarter of 2020, we continued to identify opportunities for cost reductions and operating efficiencies in all areas of our operations, while also searching for new producing property acquisition opportunities. Acquisition efforts have been, and we believe will continue to be, focused on PDP-heavy assets where we might also be able to leverage our geological and operational experience and expertise to reduce operating expenses, enhance production and identify and develop additional drilling opportunities that we believe will enable the Company to economically grow production and add reserves.

On June 5, 2020, we announced the addition of a new corporate business line that includes offering a property management service (or a "fee for service") for oil and natural gas companies with distressed or stranded assets, or companies with a desire to reduce administrative costs by engaging a contract operator of its oil and gas assets. As part of this service offering, we entered into a Management Services Agreement ("MSA") with Mid-Con, effective July 1, 2020, to provide services as contract operator of record on Mid-Con's oil and natural gas properties, along with certain administrative and management services, in exchange for an annual services fee of $4 million, paid ratably over the twelve month period, plus reimbursement of certain costs and expenses, a deferred fee of $166,666 per month for each month that the agreement is in effect (not to exceed $2 million), to be paid in a lump sum upon termination of the agreement, and warrants to purchase a minority equity ownership in Mid-Con. In connection with the Company's acquisition of Mid-Con on January 21, 2021, the MSA was terminated, the deferred fee obligation was forgiven, and the warrants were cancelled. See Note 4 – "Acquisitions and Dispositions" for more information. We recorded $2.0 million in revenue during the year ended December 31, 2020 related to the MSA with Mid-Con, which is included in "Fee for services revenue" in the Company's consolidated statements of operations.

On June 8, 2020, the stockholders of the Company, at the Company's 2020 Annual Meeting of Stockholders, approved an amendment (the "Charter Amendment") to the Company's Amended and Restated Certificate of Formation with the Secretary of State of the State of Texas to increase the number of authorized shares of common stock, par value of $0.04 per share, of the Company from 200,000,000 shares to 400,000,000 shares, and also approved the conversion of the 2,700,000 shares of the Series C contingent convertible preferred stock, par value $0.04 per share into 2,700,000 shares of the Company's common stock. On June 10, 2020, we filed the Charter Amendment with the Secretary of State of the State of Texas.

On June 24, 2020, we entered into an Open Market Sale Agreement (the "Sale Agreement") among the Company and Jefferies LLC (the "Sales Agent"). Pursuant to the terms of the Sale Agreement, we may sell, from time to time through the Sales Agent in the open market, subject to satisfaction of certain conditions, shares of the Company's common stock, having an aggregate public offering price of up to $100,000,000 (the "Shares") (the "ATM Program"). We intend to use the net proceeds from any sales through the ATM Program, after deducting the Sales Agent's commission and any offering expenses, to repay borrowings under our Credit Agreement and for general corporate purposes, including, but not limited to, acquisitions and exploratory drilling. Under the ATM Program, we sold 163,929 shares during the year ended December 31, 2020 for net proceeds of $0.5 million.

On October 25, 2020, we entered into an agreement and plan of merger with Mid-Con providing for the acquisition by the Company of Mid-Con in an all-stock merger transaction in which Mid-Con would become a direct, wholly owned subsidiary of Contango. The Mid-Con Acquisition closed on January 21, 2021, at which time the MSA between Contango and Mid-Con was terminated. On October 30, 2020, we entered into the Third Amendment (the "Third Amendment") to our Credit Agreement which, among other things, increased the Company's borrowing base from $75 million to $130 million, effective upon the closing of the Mid-Con Acquisition, with an automatic $10.0 million reduction in the borrowing base on March 31, 2021. A total of 25,409,164 shares of Contango common stock were issued at the closing of the Mid-Con Acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

Concurrently with the announcement of the Mid-Con Acquisition, on October 27, 2020, we completed a private placement of 26,451,988 shares of common stock with a select group of institutional and accredited investors for net proceeds of approximately $38.8 million, after deducting the underwriting discount and fees and expenses. The use of those proceeds was in connection with the Mid-Con Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

On November 27, 2020, we entered into a purchase and sale agreement with an undisclosed seller to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico (collectively the "Silvertip Acquisition") for aggregate consideration of approximately $58 million. The Silvertip Acquisition closed on February 1, 2021, for a net consideration of approximately $53.2 million in cash after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date. See Note 4 – "Acquisitions and Dispositions" for more information.

On December 1, 2020, we completed a private placement of 14,193,903 shares of common stock for net proceeds of approximately $21.7 million, after deducting the underwriting discount and fees and expenses. The net proceeds were used to fund the Silvertip Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

For 2021, we believe that a continuing challenging commodity price environment, and a shortage of capital available to the energy industry, may present more opportunities to acquire additional producing properties that could provide strong production, cash flow and future development potential at attractive rates of return. We plan to be active in pursuing such acquisition opportunities and then allowing our technical teams to leverage our experience and expertise to work on increasing returns through cost reduction, production enhancement and future development of the undeveloped drilling locations that come with the production acquired. We can provide no assurances that we will acquire any producing property opportunities on attractive terms, or at all, or that we will realize the expected benefits of any acquisition. We currently have a conservative capital expenditure program planned for 2021 and plan to limit that program to drilling and workover projects that we believe may provide compelling returns in this current commodity price environment or where necessary to preserve strategic acreage in our core areas, while simultaneously continuing to make balance sheet strength a priority in 2021 as we utilize excess cash flow to reduce debt and increase our capacity to quickly react to acquisition opportunities.

As we focus on the above stated initiatives, we also plan to continue to sell non-core assets to improve overall margins, to provide incremental liquidity, to reduce future asset retirement obligations and to improve our balance sheet. In 2020, we sold certain producing and non-producing properties located in our Central Oklahoma and Western Anadarko regions. These non-core, marginally economic properties were a minor portion of the value of properties acquired from Will Energy and White Star and were sold in exchange for approximately $0.5 million in cash and the buyers' assumption of the plugging and abandonment liabilities and revenue held in suspense on those properties. The Company recorded a gain of $4.4 million as a result of the buyers' assumption of the asset retirement obligations associated with the sold properties.

Production and Reserve Overview

Our production sales for the year ended December 31, 2020 were approximately 6.1 MMBoe (or 16.7 MBoe/d), comprised of 27% oil, 52% natural gas and 21% NGLs. Our production sales for the three months ended December 31, 2020 were approximately 1.3 MMBoe (or 14.4 MBoe/d), comprised of 28% oil, 49% natural gas and 23% NGLs. Our onshore properties contributed approximately 82% and 84% of our total production sales for the three and twelve months ended December 31, 2020, respectively.

As of December 31, 2020, our proved reserves, as estimated by William M. Cobb and Associates ("Cobb"), our independent petroleum engineering firm, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission ("SEC"), were approximately 34.2 MMBoe, consisting of 13.0 MMBbl of oil and condensate, 84.5 Bcf of natural gas and 7.2 MMBbl of natural gas liquids ("NGLs"). As of December 31, 2020, our proved reserves were approximately 80% proved developed (volumetrically), approximately 88% were onshore properties, and approximately 98% of total volumes were attributed to wells and properties operated by us.

As of December 31, 2020, our proved reserves had a present value, discounted at a 10% rate based on year-end SEC pricing guidelines ("PV-10"), of $126.4 million. PV-10 as of December 31, 2020 was based on SEC prices of $39.57 per barrel of oil and $2.14 per MMBtu of natural gas. Resulting realized prices, after adjustments and differentials across all assets, were $36.57 per barrel of oil, $1.86 per MMBtu of natural gas and $12.43 per barrel of NGL. As of December 31, 2020, our proved reserves were approximately 89% of total PV-10 proved developed, approximately 92% of total PV-10 onshore and approximately 98% of total PV-10 attributed to wells and properties operated by us. PV-10 is not an accounting principle generally accepted in the United States of America ("GAAP") and is therefore classified as a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties - PV-10". As of December 31, 2020, our proved reserves had a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $115.6 million, in comparison to a Standardized Measure of $257.8 million as of December 31, 2019.

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2020 (excluding proved reserves attributable to our 37% equity investment in Exaro), as estimated by Cobb, and our net average daily production for the year ended December 31, 2020:

Region	Estimated Proved Reserves (MMBoe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (MBoe/d)
Offshore GOM	4.2	4 %	83 %	13 %	100 %	2.7
Central Oklahoma	15.4	27 %	46 %	27 %	99 %	9.5
Western Anadarko	4.9	18 %	53 %	29 %	97 %	2.4
West Texas	8.3	87 %	4 %	9 %	22 %	1.0
Other Onshore (1)	1.4	39 %	41 %	20 %	100 %	1.1
Total	34.2					16.7

(1) Includes areas in East, South and Southeast Texas, Louisiana, Wyoming and Mississippi.

The following summary table sets forth certain information with respect to the proved reserves attributable to our equity-method investment in Exaro, as of December 31, 2020, as estimated by W.D. Von Gonten and Associates ("Von Gonten"), and our net share of Exaro's average daily production for the year ended December 31, 2020:

Region	Estimated Proved Reserves (MMBoe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (MBoe/d)
Investment in Exaro	2.6	6 %	94 %	— %	100 %	2.7

Our Strategy

Our long-term business strategy is:

• *Pursuing accretive, opportunistic acquisitions that meet our short-term and long-term strategic and financial objectives.* We believe that there is currently a window of opportunity for us to acquire PDP-heavy assets that also possess sizable undeveloped acreage positions from distressed and/or motivated sellers at an attractive discount to PDP PV-10 valuations. Consequently, we currently intend to focus our future growth efforts on identifying, evaluating and pursuing the acquisition of such oil and natural gas properties in areas where we currently have a presence and/or specific operating expertise that will position us to enhance our expected acquisition returns through leveraging our operational experience and expertise in order to provide productivity and cost-reduction improvements, and where appropriate, increase reserves through development drilling. We may acquire individual properties or private or publicly traded companies, in each case for cash, common stock, preferred stock or a combination thereof. We believe that the ongoing challenging commodity price environment, and very limited sources of debt and/or equity capital available to our industry, should provide significant reserve and cash flow growth opportunity for us through potential corporate combinations that provide an attractive mix of significant cash flow and undeveloped growth potential.

• *Enhancing our existing portfolio by dedicating the majority of our capital expenditures to our existing portfolio of oil and liquids-rich opportunities*. A key element of our long-term strategy is to continue to develop the oil and natural gas liquids resource potential that we believe exists in numerous formations within our various oil/liquids weighted resource plays, and where possible, to expand our presence in those plays. Due to the current superior economics of oil production, as compared to natural gas, we expect to focus on oil and liquids-weighted opportunities as we believe that liquids-heavy assets currently provide the potential for more attractive investment economics, although we will not rule out the acquisition of gas weighted properties if we believe the acquisition is accretive to our shareholders. In response to the continuing challenging commodity price environment, and the current opportunity to be an asset consolidator in the industry, we plan to limit near-term drilling capital for the foreseeable future to that necessary to fulfill leasehold commitments, and preserve core acreage when appropriate, and where the opportunity exists, to drill on acquired acreage where we can add production and cash flow at attractive rates of return. We will, however, continue to evaluate high quality drilling opportunities that have the potential to add significant reserves and cash flow to our portfolio at low finding and development cost, such as our shallow water Gulf of Mexico exploratory prospects.

• *2021 business strategy*. During 2021, we intend to continue to minimize our drilling program, pursue additional "fee for service" opportunities similar to the now terminated Management Services Agreement entered into with Mid-Con, as well as pursue growth through the acquisition of PDP-heavy assets and use excess cash flow for the reduction in borrowings outstanding under our Credit Agreement. We will also be keenly focused on continuing to reduce lease operating costs and general and administrative expenses, and on improving cash margins and lowering our exposure to asset retirement obligations through the possible sale of additional non-core properties. We will continue to make balance sheet strength a priority in 2021 and will continue to evaluate certain acquisition opportunities that may arise in this challenging commodity price environment. We will retain the flexibility to be more aggressive in our drilling plans should planned results exceed expectations, commodity prices improve or we reduce drilling and completion costs in certain areas, thereby making an expansion of our drilling program an appropriate business decision. Our 2021 capital expenditure budget is currently planned to be between $13 - $16 million for capital workovers, facility upgrades, waterflood development and selected new well drills; however, due to our ongoing evaluation of future development for our recently acquired properties from the Mid-Con Acquisition and the Silvertip Acquisition, and the regulatory and operational considerations to consider in our GOM program, our capital expenditure program will continue to be evaluated for revision during the year. We believe that we will have the financial resources to increase the currently planned 2021 capital expenditure budget, when and if deemed appropriate, including as a result of changes in commodity prices, economic conditions or operational factors.

Properties

As of December 31, 2020, our properties were located in the following regions: Offshore GOM, Central Oklahoma, Western Anadarko, West Texas and Other Onshore.

Offshore Gulf of Mexico

As of December 31, 2020, our offshore assets consisted of seven company-operated wells in the shallow waters of the GOM off of the coast of Louisiana. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2020 and average daily offshore production sales for the year ended December 31, 2020:

Field	Estimated Proved Reserves (MMBoe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (MBoe/d)
Dutch and Mary Rose	4.2	4 %	83 %	13 %	100 %	2.7
Total	4.2					2.7

Dutch and Mary Rose Field

We currently operate five producing wells located in federal waters at Eugene Island 10 ("Dutch"), and two producing wells located in adjacent Louisiana state waters ("Mary Rose"). Our offshore average daily production sales for three months ended December 31, 2020 were approximately 2.5 MBoe per day (20% liquids). All Dutch and Mary Rose wells flow to a Company-owned and operated production platform at Eugene Island 11. While we do not own the lease for the Eugene Island 11 block, this does not impact our ability to operate our facilities located on that block. Operators in the GOM may place platforms and facilities on any location without having to own the lease, provided that permission and proper permits from the Bureau of Safety and Environmental Enforcement ("BSEE") have been obtained. We have obtained such permission and permits. We installed our facilities at Eugene Island 11 because that was the optimal gathering location in proximity to our wells and marketing pipelines.

From our production platform we are able to access two separate oil and natural gas markets thereby minimizing downtime risk and providing the ability to select the best sales price for our oil and natural gas production. Oil and natural gas production can flow through our 20" gas pipeline to third-party owned and operated onshore processing facilities near Patterson, Louisiana. Alternatively, natural gas can flow via our 8" pipeline to a third-party owned and operated onshore processing facility southwest of Abbeville, Louisiana, and oil can flow via a 6" oil pipeline to third-party owned and operated onshore processing facilities in St. Mary Parish, Louisiana. Production facilities include a turbine type compressor capable of servicing all Dutch and Mary Rose wells at the Eugene Island 11 platform. Condensate can also flow to onshore markets and multiple refineries.

Gulf of Mexico Exploratory Prospects

In December 2019, we entered into a Joint Development Agreement with Juneau, that provides the Company the right to acquire an interest in up to six of Juneau's prospects located in the Gulf of Mexico. The first such prospect acquired by the Company was the Iron Flea prospect located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline, which was determined to be unsuccessful in June 2020. The Company is currently evaluating for future testing a number of exploratory prospects included in the Joint Development Agreement, including the Boss Hogg prospect located in the Eugene Island 298 Area in the shallow waters off of the Louisiana coastline. Management considers this Boss Hogg prospect to be an excellent complement to its PDP-oriented acquisition strategy and believes it could provide a very compelling economic value proposition, even in the current low oil price environment. We are currently working through regulatory considerations and operational factors, including the availability of appropriate equipment, in determining the ultimate strategy for, and timing on, the testing of that prospect.

Central Oklahoma

During the three months ended December 31, 2019, we acquired producing properties in the Will Energy Acquisition and White Star Acquisition that are located in the Central Oklahoma region and are primarily in the Woodford, Meramec, Mississippian, Chester, Oswego and Hunton formations. In December 2019, we completed and brought on production a Garfield County, Oklahoma well, which we acquired in connection with the White Star

Acquisition. As of December 31, 2020, the Central Oklahoma region included approximately 629,100 gross (257,700 net) acres, proved reserves of 15.4 MMBoe (54% oil/liquids) and 674 gross (342.3 net) producing wells. Our average daily production sales for the year ended December 31, 2020 were approximately 9,500 Boe per day, and we operated 63% of our Central Oklahoma producing properties as of December 31, 2020. Our focus in this area in 2020 was on the reduction in lease operating expenses to enhance economic returns. We made progress through that program and were able to lower forecasted operating expenses for 2020 year-end reserves by 43% compared to the 2019 year-end reserves. This improvement in lease operating expenses during 2020 was the basis of a $38.5 million improvement in the present value of the 2020 year-end proved reserves for this region. We did not drill in this region during 2020, and while no drilling is currently planned for this region in 2021, we do plan to pursue an active production-enhancing workover program in the area during 2021.

Western Anadarko

During the three months ended December 31, 2019, we acquired producing properties in the Will Energy Acquisition and White Star Acquisition that are located in the Western Anadarko region and are primarily in the Chester, Tonkawa, Morrow, Marmaton, Cottage Grove, Red Fork and Cleveland formations. We did not drill in this region during the year ended December 31, 2020, as our focus in this area, similar to the Central Oklahoma region, was on the reduction in lease operating costs to enhance economic returns. We made progress through that program and were able to lower forecasted operating expenses for 2020 year-end reserves by 47% compared to the 2019 year-end reserves. This improvement in costs was the basis of a $3.1 million improvement in the present value of the 2020 year-end proved reserves for this region. As of December 31, 2020, the Western Anadarko region included approximately 274,600 gross (144,500 net) acres, proved reserves of 4.9 MMBoe (47% oil/liquids) and 400 gross (196.9 net) producing wells. Our average daily production sales for the year ended December 31, 2020 were approximately 2,400 Boe per day, and we operated 50% of our Western Anadarko producing properties as of December 31, 2020. No drilling is currently planned for this region in 2021.

West Texas

Southern Delaware Basin

We and our 50% non-operated working interest partner in the Southern Delaware Basin own approximately 16,200 gross acres (7,500 net acres to Contango). As of December 31, 2020, we estimate that we have net proved reserves of 8.3 MMBoe (87% oil, 96% total liquids) in our West Texas region.

In the first quarter of 2020, and in response to low commodity prices and a related window of opportunity to acquire producing properties on attractive terms, we suspended our drilling program in the Southern Delaware Basin. We believe we have 68 gross (27.5 net) potential drilling locations in the Wolfcamp A and B areas of our acreage, substantially all of which we believe can accommodate 10,000 foot laterals that could provide a basis for future development and reserve growth in a more favorable and stable oil price environment. Included in the 68 gross locations are 32 proved undeveloped locations and 36 unbooked locations. If the recent improvement in oil prices is sustained, some capital could be allocated to the drilling of proved undeveloped locations in this area during 2021. As of December 31, 2020, we had 13 wells producing from Wolfcamp A and five wells producing from Wolfcamp B, that produced at an average rate of approximately 1,000 Boe per day during the year ended December 31, 2020.

Other Onshore

Our Other Onshore region is comprised of various smaller non-core producing areas in Texas, Louisiana, Wyoming and Mississippi. As of December 31, 2020, our estimated net proved reserves for the properties in this region are 1.4 MMBoe.

Texas

Our Southeast Texas area includes approximately 19,500 gross (11,700 net) acres in Madison and Grimes counties, with the potential for a multi-year inventory of drilling locations encompassing the Woodbine, Eagle Ford Shale and/or Georgetown/Buda formations in an improved oil price environment. We had proved reserves of 0.7 MMBoe (73% oil/liquids) and 37 gross (20.0 net) producing wells in Southeast Texas as of December 31, 2020.

Our South Texas area includes properties in Dimmitt and Zavala counties, which include approximately 16,100 gross (6,600 net) acres that we believe to be prospective for the Buda, Georgetown and Eagle Ford Shale plays in an improved price environment. Our South Texas area also includes approximately 14,300 gross (7,300 net) acres located in conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved reserves in this area were 1.3 MMBoe (44% oil/liquids) with 39 gross (17.6 net) producing wells, as of December 31, 2020.

Our East Texas area includes approximately 5,900 gross (3,600 net) acres primarily in San Augustine County, with proved reserves of 0.2 MMBoe (26% oil/liquids) and 8 gross (4.7 net) wells producing in the Haynesville, Mid-Bossier and/or James Lime formations. There has been renewed interest in this area by offset operators as they experiment with new frac techniques and refracing of previously drilled wells.

No drilling capital has been allocated to these Texas areas since 2015 due to the challenging commodity price environment and our focus on our West Texas region properties, with the exception of four successful non-operated Georgetown wells in which we participated in drilling from 2017 through 2019.

Louisiana

As of December 31, 2020, the estimated proved reserves for our Louisiana properties were 0.5 MMBoe (56% oil/liquids) primarily related to the properties we acquired in the Will Energy Acquisition.

Wyoming

In 2015, we drilled the first of three successful wells in this area targeting the Muddy Sandstone formation. Based on prior drilling results, a sustained improvement in oil prices will be needed to justify allocation of drilling capital to this area at the expense of other areas in our portfolio that provide higher returns. As of December 31, 2020, our Wyoming area includes approximately 33,200 gross (23,000 net) net acres with estimated proved reserves of 0.1 MMBoe (91% oil) as of December 31, 2020.

Mississippi

As of December 31, 2020, we held approximately 1,300 gross (300 net) mostly undeveloped acres in Mississippi.

Impairment of Long-Lived Assets

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field-by-field basis to the unamortized capitalized cost of the assets in that field. In the first quarter of 2020, the COVID-19 pandemic and the resulting deterioration in the global demand for oil, combined with the failure by OPEC and Russia to reach an agreement on lower production quotas until April 2020, caused a dramatic increase in the supply of oil, a corresponding decrease in commodity prices, and reduced the demand for all commodity products. Consequently, during the first quarter of 2020, we recorded a $143.3 million non-cash charge for proved property impairment of our onshore properties related to the dramatic decline in commodity prices, the PV-10 of our proved reserves, and the associated change in our current development plans for proved, undeveloped locations. In the fourth quarter of 2020, we recorded an additional $21.1 million non-cash charge for proved property impairment, of which $15.6 million related to our offshore properties as a result of performance revisions in reserves and the decline in gas prices and production yield. The total non-cash proved property impairment recorded during the year ended December 31, 2020 was $164.4 million.

Unproved properties are reviewed quarterly to determine if there has been an impairment of the carrying value, with any such impairment charged to expense in the period. During the year ended December 31, 2020, we recorded a $4.3 million non-cash charge for unproved impairment expense related to undeveloped leases in our Central Oklahoma, Western Anadarko and Other Onshore regions. We recorded $2.6 million of this impairment expense in the first quarter of 2020, primarily related to leases we acquired from White Star and Will Energy in the fourth quarter of 2019, which were expiring in 2020, and we recorded $1.7 million of this impairment expense in the fourth quarter of 2020, due to leases expiring in 2021, all of which we have no plans to extend or develop as a result of the current commodity price environment and our continued focus on cost saving and production enhancing initiatives.

Onshore Investments

Jonah Field – Sublette County, Wyoming

Our wholly-owned subsidiary, Contaro Company ("Contaro"), owns a 37% ownership interest in Exaro. As of December 31, 2020, we had invested approximately $46.9 million in Exaro, with no requirement to make any additional equity contributions, as our commitment to invest additional capital in Exaro expired on March 31, 2017. We account for Contaro's ownership in Exaro using the equity method of accounting, and therefore, do not include its share of individual operating results, reserves or production in those reported in our consolidated results.

As of December 31, 2020, Exaro had 645 wells on production over its 5,760 gross acres (1,040 net acres), with a working interest between 14.6% and 32.5%. These wells were producing at a rate of approximately 2.5 MBoe/d, net to Contango, during the three months ended December 31, 2020. For the year ended December 31, 2020, we recognized a net investment gain of approximately $27,000, net of zero tax expense, as a result of our equity investment in Exaro. As of December 31, 2020, reserves attributable to our investment in Exaro were 2.6 MMBoe. See Note 11 - "Investment in Exaro Energy III LLC" for additional details related to this equity investment.

Title to Properties

From time to time, we are involved in legal proceedings relating to claims associated with ownership interests in our properties. We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, and liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed independent third-party attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our oil and natural gas properties to secure our Credit Agreement. These mortgages and the related Credit Agreement contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 13 to our Financial Statements - "Long-Term Debt" for further information.

Marketing and Pricing

We derive our revenue principally from the sale of oil and natural gas. As a result, our revenues are determined, to a large degree, by prevailing oil and natural gas prices. We sell a portion of oil and condensate production to purchasers under sales agreements with primary terms of up to one year and our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to three years. The sale prices for oil are tied to industry standard posted prices, subject to negotiated price adjustments, while the sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments

We typically utilize commodity price hedge instruments to minimize exposure to declining prices on our oil, natural gas and natural gas liquids production, by using a series of swaps and/or costless collars. Unrealized gains or losses associated with hedges vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities being hedged.

We currently have derivative contracts in place to cover production periods through the first quarter of 2023, which include the hedges novated from Mid-Con and the additional hedges entered into in the first quarter of 2021, as discussed below. These contracts include oil hedges for 2.1 MMBbls of 2021 production with average floor prices of $54.85 per barrel and 1.4 MMBbls of 2022 production with average floor prices of $50.24 per barrel. For natural gas, our derivative contracts include 12.4 Bcf of 2021 production with average floor prices of $2.62 per MMBtu and 10.1 Bcf of 2022 production with average floor prices of $2.60 per MMBtu. Approximately 97% of our hedges are swaps, and we have no three-way collars or short puts.

As of December 31, 2020, we had the following derivative contracts in place:

Commodity	Period	Derivative	Volume/Month		Price/Unit		
Oil	Jan 2021 - March 2021	Swap	19,000	Bbls	$	50.00	(1)
Oil	April 2021 - July 2021	Swap	12,000	Bbls	$	50.00	(1)
Oil	Aug 2021 - Sept 2021	Swap	10,000	Bbls	$	50.00	(1)
Oil	Jan 2021 - July 2021	Swap	62,000	Bbls	$	52.00	(1)
Oil	Aug 2021 - Sept 2021	Swap	55,000	Bbls	$	52.00	(1)
Oil	Oct 2021 - Dec 2021	Swap	64,000	Bbls	$	52.00	(1)
Oil	April 2022 - Oct 2022	Swap	25,000	Bbls	$	42.04	(1)
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$	2.505	(2)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$	2.505	(2)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$	2.505	(2)
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$	2.508	(2)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$	2.508	(2)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$	2.508	(2)
Natural Gas	Jan 2021 - March 2021	Swap	650,000	MMBtus	$	2.508	(2)
Natural Gas	April 2021 - Oct 2021	Swap	400,000	MMBtus	$	2.508	(2)
Natural Gas	Nov 2021 - Dec 2021	Swap	580,000	MMBtus	$	2.508	(2)
Natural Gas	April 2021 - Nov 2021	Swap	70,000	MMBtus	$	2.36	(2)
Natural Gas	Dec 2021	Swap	350,000	MMBtus	$	2.36	(2)
Natural Gas	Jan 2022 - March 2022	Swap	780,000	MMBtus	$	2.542	(2)
Natural Gas	April 2022 - July 2022	Swap	650,000	MMBtus	$	2.515	(2)
Natural Gas	Aug 2022 - Oct 2022	Swap	350,000	MMBtus	$	2.515	(2)
Natural Gas	Jan 2022 - March 2022	Swap	250,000	MMBtus	$	3.149	(2)

(1) Based on West Texas Intermediate oil prices

(2) Based on Henry Hub NYMEX natural gas prices.

In conjunction with the closing of the Mid-Con Acquisition in January 2021, we acquired the following additional derivative contracts via novation from Mid-Con:

Commodity	Period	Derivative	Volume/Month		Price/Unit
Oil	Jan 2021	Swap	20,883	Bbls	$ 55.78 (1)
Oil	Feb 2021	Swap	20,804	Bbls	$ 55.78 (1)
Oil	March 2021	Swap	20,725	Bbls	$ 55.78 (1)
Oil	April 2021	Swap	20,647	Bbls	$ 55.78 (1)
Oil	May 2021	Swap	20,563	Bbls	$ 55.78 (1)
Oil	June 2021	Swap	20,487	Bbls	$ 55.78 (1)
Oil	July 2021	Swap	20,412	Bbls	$ 55.78 (1)
Oil	Aug 2021	Swap	20,301	Bbls	$ 55.78 (1)
Oil	Sept 2021	Swap	20,228	Bbls	$ 55.78 (1)
Oil	Oct 2021	Swap	20,155	Bbls	$ 55.78 (1)
Oil	Nov 2021	Swap	20,084	Bbls	$ 55.78 (1)
Oil	Dec 2021	Swap	20,012	Bbls	$ 55.78 (1)
Oil	Jan 2021	Collar	20,883	Bbls	$ 52.00 - 58.80 (1)
Oil	Feb 2021	Collar	20,804	Bbls	$ 52.00 - 58.80 (1)
Oil	March 2021	Collar	20,725	Bbls	$ 52.00 - 58.80 (1)
Oil	April 2021	Collar	20,647	Bbls	$ 52.00 - 58.80 (1)
Oil	May 2021	Collar	20,563	Bbls	$ 52.00 - 58.80 (1)
Oil	June 2021	Collar	20,487	Bbls	$ 52.00 - 58.80 (1)
Oil	July 2021	Collar	20,412	Bbls	$ 52.00 - 58.80 (1)
Oil	Aug 2021	Collar	20,301	Bbls	$ 52.00 - 58.80 (1)
Oil	Sept 2021	Collar	20,228	Bbls	$ 52.00 - 58.80 (1)
Oil	Oct 2021	Collar	20,155	Bbls	$ 52.00 - 58.80 (1)
Oil	Nov 2021	Collar	20,084	Bbls	$ 52.00 - 58.80 (1)
Oil	Dec 2021	Collar	20,012	Bbls	$ 52.00 - 58.80 (1)

(1) Based on West Texas Intermediate oil prices

In the first quarter of 2021, we entered into the following additional derivative contracts:

Commodity	Period	Derivative	Volume/Month		Price/Unit		
Oil	March 2021 - Oct 2021	Swap	25,000	Bbls	$	54.77	(1)
Oil	Nov 2021 - Dec 2021	Swap	15,000	Bbls	$	54.77	(1)
Oil	March 2021	Swap	50,000	Bbls	$	63.31	(1)
Oil	April 2021	Swap	50,000	Bbls	$	63.13	(1)
Oil	May 2021	Swap	50,000	Bbls	$	62.71	(1)
Oil	June 2021	Swap	50,000	Bbls	$	62.17	(1)
Oil	July 2021	Swap	50,000	Bbls	$	61.50	(1)
Oil	Aug 2021	Swap	50,000	Bbls	$	60.94	(1)
Oil	Sep 2021	Swap	50,000	Bbls	$	60.38	(1)
Oil	Oct 2021	Swap	50,000	Bbls	$	59.89	(1)
Oil	Nov 2021	Swap	50,000	Bbls	$	59.46	(1)
Oil	Dec 2021	Swap	50,000	Bbls	$	59.01	(1)
Oil	Jan 2022	Swap	60,000	Bbls	$	52.94	(1)
Oil	Feb 2022	Swap	60,000	Bbls	$	52.65	(1)
Oil	March 2022	Swap	60,000	Bbls	$	52.29	(1)
Oil	April 2022	Swap	47,500	Bbls	$	51.98	(1)
Oil	May 2022	Swap	45,000	Bbls	$	51.71	(1)
Oil	June 2022	Swap	45,000	Bbls	$	51.41	(1)
Oil	July 2022	Swap	45,000	Bbls	$	51.13	(1)
Oil	Aug 2022	Swap	45,000	Bbls	$	50.89	(1)
Oil	Sep 2022	Swap	45,000	Bbls	$	50.65	(1)
Oil	Oct 2022	Swap	45,000	Bbls	$	50.45	(1)
Oil	Nov 2022	Swap	55,000	Bbls	$	50.26	(1)
Oil	Dec 2022	Swap	55,000	Bbls	$	50.22	(1)
Oil	Jan 2023	Swap	57,500	Bbls	$	49.81	(1)
Oil	Feb 2023	Swap	57,500	Bbls	$	49.63	(1)
Oil	Jan 2022	Swap	60,000	Bbls	$	52.96	(1)
Oil	Feb 2022	Swap	60,000	Bbls	$	52.66	(1)
Oil	March 2022	Swap	60,000	Bbls	$	52.27	(1)
Oil	April 2022	Swap	47,500	Bbls	$	51.96	(1)
Oil	May 2022	Swap	45,000	Bbls	$	51.72	(1)
Oil	June 2022	Swap	45,000	Bbls	$	51.42	(1)
Oil	July 2022	Swap	45,000	Bbls	$	51.13	(1)
Oil	Aug 2022	Swap	45,000	Bbls	$	50.90	(1)
Oil	Sep 2022	Swap	45,000	Bbls	$	50.66	(1)
Oil	Oct 2022	Swap	45,000	Bbls	$	50.47	(1)
Oil	Nov 2022	Swap	55,000	Bbls	$	50.26	(1)
Oil	Dec 2022	Swap	55,000	Bbls	$	50.01	(1)
Oil	Jan 2023	Swap	57,500	Bbls	$	49.79	(1)
Oil	Feb 2023	Swap	57,500	Bbls	$	49.62	(1)
Natural Gas	March 2021	Swap	100,000	MMBtus	$	2.96	(2)
Natural Gas	April 2021 - July 2021	Swap	350,000	MMBtus	$	2.96	(2)
Natural Gas	Aug 2021 - Oct 2021	Swap	500,000	MMBtus	$	2.96	(2)
Natural Gas	Nov 2021	Swap	450,000	MMBtus	$	2.96	(2)
Natural Gas	April 2022	Swap	175,000	MMBtus	$	2.51	(2)
Natural Gas	May 2022 - July 2022	Swap	150,000	MMBtus	$	2.51	(2)
Natural Gas	Aug 2022 - Oct 2022	Swap	400,000	MMBtus	$	2.51	(2)
Natural Gas	Nov 2022 - Feb 2023	Swap	750,000	MMBtus	$	2.72	(2)

(1) Based on West Texas Intermediate oil prices

(2) Based on Henry Hub NYMEX natural gas prices.

Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. Our three largest purchasers contributed approximately 36% of our total production revenues for the year ended December 31, 2020. This concentration may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

The oil and natural gas industry is highly competitive, and we compete with numerous other companies. Our competitors in the exploration, development, acquisition and production business include major integrated oil and natural gas companies as well as numerous independent companies, including many that have significantly greater financial resources.

The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties and obtaining purchasers and transporters for the oil and natural gas we produce. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Governmental Regulations and Industry Matters

Industry Regulations

The availability of a ready market for oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of oil, natural gas and natural gas liquids production, federal, state and local regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of oil, natural gas and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or lack of an available natural gas pipeline in the area in which the well is located. State and federal regulations generally are intended to prevent waste of oil, natural gas and natural gas liquids, protect rights to produce oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of oil, natural gas and natural gas liquids produced by assigning allowable rates of production, and protect the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the U.S. oil and natural gas industry. Such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Oil, Natural Gas and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws, which establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil, natural gas and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938 (the “NGA”), the Federal Energy Regulatory Commission (the “FERC”) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the “Decontrol Act”) deregulated natural gas prices for all “first sales” of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC’s jurisdiction over natural gas transportation.

Section 1(b) of the NGA exempts gas gathering facilities from the FERC’s jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. While we own some gas gathering facilities, we also depend on gathering facilities owned and operated by third parties to gather production from our properties, and therefore, we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, we also may be affected by these changes. Accordingly, we do not anticipate that we would be affected any differently than similarly situated gas producers.

Under the provisions of the Energy Policy Act of 2005 (the “2005 Act”), the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission (the “CFTC”) also holds authority to monitor certain segments of the physical and derivative futures commodity markets including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. FERC holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of approximately $1.29 million per day per violation, subject to annual adjustment for inflation. CFTC also holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of up to approximately $1.21 million per violation or triple the monetary gain.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. For example, on December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC’s policy statement on price reporting. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. In addition, to the extent that we transport gas on interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC's regulations could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978 (the "NGPA"), the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required interstate pipelines, among other things, to perform "open access" transportation of gas for others, "unbundle" their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular interstate pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. FERC's policies regarding the interstate transportation of natural gas are subject to change from time to time, and such changes could impact access to markets, competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the natural gas industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to potentially assess maximum civil penalties of approximately $1.23 million per day per violation, subject to annual adjustment for inflation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines whose transportation rates are subject to FERC regulation. FERC allows common carrier pipelines to establish rates via contract, traditional rate regulation, market rates or "index." Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of oil and natural gas liquids transportation rates may tend to increase the cost of transporting oil and natural gas liquids by interstate pipelines, although the annual index rate adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with oil production from our oil producing operations.

There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of petroleum with which we compete.

Environmental and Occupational Health and Safety Matters

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders enjoining some or all of our operations in affected areas. The public continues to have a significant interest in the protection of the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment, and thus any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly exploration, production and development activities, or waste handling, storage transport, disposal or remediation requirements could result in increased costs of our doing business and consequently affect our profitability. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund Law", and similar state laws, impose strict joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the current or past owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resource damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate wastes that are subject to the federal Resource Conservation and Recovery Act, as amended (the "RCRA"), and comparable state statutes. The RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous wastes, and the EPA and analogous state agencies stringently enforce the approved methods of management and disposal of these wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we can provide no assurance that this exemption will be preserved in the future. Any removal of this exclusion could increase the amount of waste we are required to manage and dispose of as hazardous waste rather than non-hazardous waste, and could cause us to incur increased operating costs, which could have a significant impact on us as well as the oil and natural gas industry in general.

The federal Clean Air Act, as amended (the "CAA"), and comparable state laws restrict the emission of air pollutants from many sources and also impose various pre-construction, operating, monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues.

There remains continued public, governmental and scientific attention regarding climate change, with the EPA having determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment. As a result, the EPA has adopted regulations under existing provisions of the CAA that, among other things, impose permit reviews and restrict emissions of GHGs from certain large stationary sources. These EPA regulations could adversely affect our operations and restrict, delay or halt our ability to obtain air permits for new or modified sources. Additionally, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including certain onshore and offshore production facilities, which include the majority of our operations. We are monitoring and annually reporting on GHG emissions from certain of our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that include consideration of cap-and-trade programs whereby major sources of GHG emissions are required to acquire and surrender emission allowances in return for emitting those GHGs, as well as carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and "represent a progression" in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. Although the United States formally withdrew from the Paris Agreement in 2020, the Biden Administration officially reentered the United States into the agreement in February 2021.

Additionally, President Biden and the Democratic Party, which now controls Congress, have identified climate change as a priority, and it is likely that new executive orders, regulatory action, and/or legislation targeting greenhouse gas emissions, or prohibiting, delaying or restricting oil and natural gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. For example, the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee, and President Biden recently announced a moratorium on new oil and natural gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. President Biden's order also establishes climate change as a primary foreign policy and national security consideration, affirms that achieving net-zero greenhouse gas emissions by or before midcentury is a critical priority, affirms President Biden's desire to establish the United States as a leader in addressing climate change, generally further integrates climate change and environmental justice considerations into government agencies' decision making, and eliminates fossil fuel subsidies, among other measures.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future international, federal or state laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

The Federal Water Pollution Control Act, as amended (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of an issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. The EPA and the U.S. Army Corps of Engineers released a rule to revise the definition of "waters of the United States," or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. However, in September 2019, the EPA repealed the 2015 rule, and in January 2020 finalized the Navigable Waters Protection Rule, which has generally been viewed as narrowing the scope of the WOTUS definition. Litigation in multiple federal district courts is currently challenging the repeal of the 2015 rule and the promulgation of the Navigable Waters Protection Rule.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended (the "SDWA"), and analogous state laws. Our oil and natural gas exploration and production operations generate produced water, drilling muds and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations, and thus, those activities are subject to the SWDA. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities that may be injected, and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for alternative water supplies, property and natural resource damages and personal injuries. Furthermore, in response to a growing concern that the injection of produced water and other fluids into belowground disposal wells triggers seismic activity in certain areas, some states, including Texas and Oklahoma, where we operate, have imposed, and other states are considering imposing, additional requirements in the permitting or operation of produced water injection wells. In Texas, the Texas Railroad Commission ("TRC") has adopted a final rule governing the permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. In Oklahoma, the Oklahoma Corporation Commission issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma in 2016. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, make sure that their wells are not injecting wastes into targeted formations, and/or reduce the volumes of wastes disposed in such wells. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for produced water disposal. These existing and any new seismic requirements applicable to disposal wells that impose more stringent permitting or operational requirements could result in added costs to comply or, perhaps, may require alternative methods of disposing of produced water and other fluids, which could delay production schedules and also result in increased costs.

The federal Oil Pollution Act of 1990, as amended (the "OPA"), and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA applies to vessels, onshore facilities and offshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities and lessees and permittees of offshore leases may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. In January 2018, the federal Bureau of Ocean Energy Management raised the OPA's damages liability cap to $137.7 million; however, while liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. The OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. The OPA currently requires a minimum financial responsibility demonstration of between $35 million and $150 million for companies operating on the federal Outer Continental Shelf ("OCS") waters, including the Gulf of Mexico. We are currently required to demonstrate, on an annual basis, that we have ready access to $35 million that can be used to respond to an oil spill from our facilities on the OCS. In addition, to the extent our offshore lease operations affect state waters, we may be subject to additional state and local clean-up requirements or incur liability under state and local laws.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or other similar state agencies, but several federal agencies have also asserted regulatory authority over, or conducted investigations that focus upon, certain aspects of the process, including a suite of proposed rulemakings and final rules issued by the EPA and the federal Bureau of Land Management (the "BLM"), which legal requirements, to the extent finalized and implemented by the agencies, may impose more stringent requirements relating to the composition of fracturing fluids, emissions and discharges from hydraulic fracturing, chemical disclosures, and performances of fracturing activities on federal and Indian lands. Congress has from time to time considered, but not enacted, legislation to provide for federal regulation or the banning of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process while, at the state level, several states, including Texas and Wyoming, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells. At various times during the past year, politicians have also proposed a ban of new leases for production of oil and gas on federal properties.

The National Environmental Policy Act, as amended ("NEPA") is applicable to oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM. NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

The federal Endangered Species Act, as amended ("ESA"), provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits taking of endangered species. The ESA may impact exploration, development and production activities on public or private lands. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act, as amended. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of one or more settlements entered into by the U.S. Fish and Wildlife Service (the "FWS"), the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA by specified timelines. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures as well as time delays or limitations on or cancellations of our drilling program activities, which costs, delays, limitations or cancellations could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

The BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have, over time, imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. For example, in 2016, the BOEM issued a Notice to Lessees and Operators (the "NTL #2016-N01") that became effective in September 2016 and bolsters supplemental financial assurance requirements for the decommissioning of offshore wells, platforms, pipelines and other facilities whereas the BSEE has issued various regulations relating to the safe and environmentally responsible development of energy and mineral resources on the OCS that have resulted in more stringent requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. Additionally, states may adopt and implement similar or more stringent legal requirements applicable to exploration and production activities in state waters. Compliance with these more stringent regulatory restrictions, together with any uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect, delay or cancel new drilling and ongoing development efforts. If the BOEM determines that increased financial assurance is required in connection with our offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled. Also, if material spill incidents were to occur, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which developments could have a material adverse effect on our business. Any of the offshore-related matters described above could have a material adverse effect on our business, financial condition and results of operations.

These regulatory actions, or any new rules, regulations or legal initiatives that may be adopted or enforced by the BOEM or the BSEE in the future could delay or disrupt our oil and natural gas exploration and production operations conducted offshore, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit or cancel activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases.

Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee, or any subsequent assignee, is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees, or any subsequent assignee, of offshore facilities is unwilling or unable to perform, we could incur costs to perform decommissioning, which costs could be material. If the BOEM determines that increased financial assurance is required in connection with our or any previously assigned offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled.

See “Item 1A. Risk Factors” for further discussion on hydraulic fracturing; ozone standards; climate change, including methane or other GHG emissions; releases of regulated substances; offshore regulatory safety and environmental development requirements, and other aspects of compliance with legal or financial assurance requirements or relating to environmental protection, including with respect to offshore leases. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards or more stringent enforcement programs continue to evolve.

Other Laws and Regulations

Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of oil and natural gas including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company’s properties and to limit the allowable production from the successful wells completed on the Company’s properties, thereby limiting the Company’s revenues.

Whereas the BLM administers oil and natural gas leases held by the Company on federal onshore lands, the BOEM administers the oil and natural gas leases held by the Company on federal offshore tracts on the OCS. The Office of Natural Resources Revenue (the “ONRR”) collects a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the ONRR changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells, decommission or remove platforms and pipelines, and clear the seafloor of obstructions at the end of production (collectively, “decommissioning obligations”), the BOEM generally requires that lessees post supplemental bonds or other acceptable financial assurances that such obligations will be met. Historically, our financial assurance costs to satisfy decommissioning obligations have not had a material adverse effect on our results of operations; however, the BOEM continues to consider imposing more stringent financial assurance requirements on offshore operators on the OCS. For example, the BOEM issued NTL #2016-N01 that went into effect in September 2016 and augments requirements for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to satisfy decommissioning obligations on the OCS. If the BOEM determines under this new NTL that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. In June 2017, the BOEM extended indefinitely the start date for implementation of NTL #2016-N01. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning obligations.

The BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the BOEM determines whether and to what extent any additional financial assurance may be required by us with respect to our offshore operations, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties. In the event that we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require certain of our operations on federal leases to be suspended or cancelled or otherwise impose monetary penalties. See "Item 1A. Risk Factors" for a further discussion on BOEM and its implementation of NTL #2016-N01.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice, and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We continuously monitor regulatory changes and regulatory responses and their impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico could lead to tighter underwriting standards, limitations on scope and amount of coverage and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

Environmental, Health and Safety Program

Our Health, Safety and Environmental ("EHS") Program is supervised by senior management to ensure compliance with all state and federal regulations. In support of the operating committee, we have contracted with J. Connor Consulting ("JCC") to coordinate the regulatory process relative to our offshore assets. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico. They provide preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills on behalf of oil and natural gas companies and pipeline operators.

Additionally, in support of our Gulf of Mexico operations, we have established a Regional Oil Spill Response Plan which has been approved by the BSEE. Our response team is trained annually and is tested through in-house spill drills. We have also contracted with O'Brien's Response Management ("O'Brien's"), who maintains an incident command center on 24 hour alert in Houston, Texas. In the event of an oil spill, the Company's response program is initiated by notifying O'Brien's of any reportable incident. While the Company response team is mobilized to focus on source control and containment of the spill, O'Brien's coordinates communications with state and federal agencies and provides subject matter expertise in support of the response team.

We also have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs in the event of a spill. CGA specializes in onsite control and cleanup and is on 24-hour alert with equipment currently stored at eight bases along the gulf coast, from South Texas to East Louisiana. The CGA equipment stockpile is available to serve member oil spill response needs and includes open seas skimmers, shoreline protection boom, communications equipment, dispersants with application systems, wildlife rehabilitation and a forward command center. CGA has retainers with aerial dispersant and mechanical recovery equipment contractors for spill response.

In addition to our membership in CGA, the Company has contracted with Wild Well Control for source control at the wellhead, if required. Wild Well Control is one of the world's leading providers of firefighting and well control services.

We also have a full-time health, safety and environmental professional who supports our operations and oversees the implementation of our onshore EHS policies.

Safety and Environmental Management System

We have developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and natural gas operations in the OCS, as required by the BSEE. Our SEMS identifies and mitigates safety and environmental hazards and the impacts of these hazards on design, construction, start-up, operation, inspection and maintenance of all new and existing facilities. The Company has established goals, performance measures, training and accountability for SEMS implementation. We also provide the necessary resources to maintain an effective SEMS, and we review the adequacy and effectiveness of the SEMS program annually. Company facilities are designed, constructed, maintained, monitored and operated in a manner compatible with industry codes, consensus standards and all applicable governmental regulations. We have contracted with Island Technologies Inc. to coordinate our SEMS program and to track compliance for production operations.

The BSEE enforces the SEMS requirements through regular audits. Failure of an audit may result in an Incident of Non-Compliance and could ultimately result in the assessment of civil penalties and/or require a shut-in of our Gulf of Mexico operations if not resolved within the required time.

Employees

On December 31, 2020, we had 205 full-time employees, of which 133 were field personnel. We have been able to attract and retain a talented team of industry professionals that have been successful in achieving significant growth and success in the past. Our employees play an important role in positioning the Company to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation of our existing asset base, as well as the continuing identification, acquisition and development of new growth opportunities. Safety is one of our greatest priorities, and we have a dedicated internal group that has implemented safety management systems, procedures and tools to help protect our employees, contractors and environment. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

In addition to our employees, we use the services of independent consultants and contractors to perform various professional services. As a working interest owner, we rely on certain outside operators to drill, produce and market our oil and natural gas where we are a non-operator. In prospects where we are the operator, we rely on drilling contractors to drill and sometimes rely on independent contractors to produce and market our oil and natural gas. In addition, we frequently utilize the services of independent contractors to perform field and on-site drilling and production operation services and independent third-party engineering firms to evaluate our reserves.

Corporate Offices

Our corporate headquarters office is located at 111 E. 5th Street, Suite 300 in Fort Worth, Texas. The Fort Worth lease was entered into effective February 1, 2021 and expires on July 31, 2023. We also have corporate offices at 717 Texas Avenue in downtown Houston, Texas, under a lease that expires on March 31, 2023 and at 301 NW 63rd Street in Oklahoma City, Oklahoma, which we acquired through the White Star Acquisition, under a lease that expires on January 31, 2022. Rent, including parking, related to these office spaces was approximately $0.5 million for the year ended December 31, 2020.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. Filings made with the SEC electronically are publicly available through the SEC's website at http://www.sec.gov, and we make these documents available free of charge at our website at http://www.contango.com as soon as reasonably practicable after they are filed or furnished with the SEC. This report on Form 10-K, including all exhibits and amendments, has been filed electronically with the SEC. We intend to use our website as a Regulation FD compliant means of making public disclosures. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

Seasonal Nature of Business

The demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters or cooler summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand.

Item 1A. ***Risk Factors***

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating the Company, as well as all other information presented in this Form 10-K. An investment in the Company is subject to risks inherent in our business, and the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, results of operations and financial condition in the future. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

Risks Related to Our Business

The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our business, financial position, results of operations, and/or cash flows will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 pandemic has resulted in a severe worldwide economic downturn, significantly disrupting the demand for oil throughout the world and has created significant volatility, uncertainty and turmoil in the oil and gas industry. This has led to a significant global oversupply of oil and a subsequent substantial decrease in oil prices. While global oil producers, including the Organization of Petroleum Exporting Countries ("OPEC") and other oil producing nations reached an agreement to cut oil production in April 2020, downward pressure on, and volatility in, commodity prices has remained and could continue for the foreseeable future, particularly given concerns over available storage capacity for oil, which have negatively affected and are expected to continue to negatively affect our cash flow, liquidity and financial position. In response to the decrease in commodity prices, beginning in the second quarter of 2020, we suspended any further plans for operated onshore and offshore drilling in 2020. Oil prices are expected to continue to be volatile as a result of these events and the ongoing COVID-19 pandemic, and as changes in oil inventories, oil demand and economic performance are reported. We cannot predict when, or to what extent, the negative effects of COVID-19 on the world and domestic economies, and on our industry and Company, will improve, or when oil prices will improve and stabilize.

While there has been a modest recovery in oil prices, the length of this demand disruption is unknown, and there is significant uncertainty regarding the long-term impact to global oil demand, which will ultimately depend on various factors and consequences beyond our control, such as the duration and spread of the pandemic, including the impact of coronavirus mutations and resurgences, its severity, the actions to contain the disease or mitigate its impact, related restrictions on travel, the development, availability and public acceptance of effective treatments or vaccines and the duration, timing and severity of the impact on domestic and global oil demand, the availability of personnel, equipment, and services critical to our ability to operate our properties, and how quickly, and to what extent, normal economic and operating conditions can resume. The COVID-19 pandemic may also precipitate or intensify the risks described in the risk factors disclosed in our 2020 Form 10-K.

We have no ability to control the market price for oil, natural gas and NGLs. Oil, natural gas and NGL prices fluctuate widely, and a continued substantial or extended decline in oil and natural gas prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on our business, results of operations and financial condition.

Our revenues, profitability and future growth depend significantly on oil, natural gas and NGL prices. Oil prices, natural gas prices and NGL prices remained low during the past several years relative to the high prices in 2014 and have been significantly adversely impacted due to the effects of the COVID-19 pandemic, despite recent recovery. The markets for these commodities are volatile and prices received affect the amount of future cash flow available for capital expenditures, repayment of indebtedness and our ability to raise additional capital. Lower prices also affect the amount of oil, natural gas and NGLs that we can economically produce. Prices fluctuate and decline based on factors beyond our control. Factors that can cause price fluctuations and declines include:

- Overall economic and market conditions, domestic and global.
- The impact of the COVID-19 pandemic, including reduced demand for oil and natural gas, economic slowdown, governmental actions and stay-at-home orders.
- The domestic and foreign supply of oil and natural gas.
- The level of consumer product demand.
- The cost of exploring for, developing, producing, refining and marketing oil, natural gas and NGLs.
- Adverse weather conditions, natural disasters, climate change and health emergencies and pandemics.
- The price and availability of competitive fuels such as LNG, heating oil and coal, and alternative fuels.
- The level of LNG imports and exports and natural gas exports.
- Political and economic conditions in the Middle East and other oil and natural gas producing regions.
- The ability of the members of OPEC and other oil exporting nations to agree to and maintain oil price and production controls.
- Domestic and foreign governmental regulations, including temporary orders limiting economic activity.
- Special taxes on production or the loss of tax credits and deductions.
- Technological advances affecting energy consumption and sources of energy supply.
- Access to pipelines and gas processing plants and other capacity constraints or production disruptions.
- The effects of energy conservation efforts, including by virtue of shareholder activism or activities of non-governmental organizations.

A substantial or extended decline in oil, natural gas and NGL prices could have a material adverse effect on our access to capital and the quantities of oil, natural gas and NGLs that may be economically produced by us. We may utilize financial derivative contracts, such as swaps, costless collars and puts on commodity prices, to reduce some of the exposure to potential declines in commodity prices. However, these derivative contracts may not be sufficient to mitigate the effect of lower commodity prices.

Part of our strategy involves drilling in new or emerging plays, and a reduction in our drilling program may affect our revenues and access to capital.

The results of our drilling in new or emerging plays are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or oil, natural gas and NGL price declines. During the quarter ended June 30, 2020, we drilled an unsuccessful exploratory well in the Gulf of Mexico, resulting in a charge of $10.5 million for drilling and prospect costs included in "Exploration expenses" in our consolidated statements of operations for the year ended December 31, 2020. Approximately $2.7 million of the exploration expense was prospect acquisition costs incurred in 2019 which were reclassified to exploration expense in 2020 as a result of the dry hole. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful. In 2020, we recorded a $4.3 million non-cash charge for unproved impairment expense related to undeveloped leases in our Central Oklahoma, Western Anadarko and Other Onshore regions. We recorded $2.6 million of this impairment expense in the first quarter of 2020, primarily related to leases we acquired from White Star and Will Energy in the fourth quarter of 2019, which were expiring in 2020, and the remaining $1.7 million of this impairment expense was recorded in the fourth quarter of 2020, due to leases expiring in 2021, all of which we have no plans to extend or develop as a result of the current commodity price environment and our continued focus on cost saving and production enhancing initiatives.

As a result of the continuing turmoil in the energy commodity price markets, we do not currently plan to commit any additional near-term drilling capital to our major areas of West Texas, Central Oklahoma, Western Anadarko or other areas within our portfolio, except to fulfill leasehold commitments and preserve core acreage where necessary and, where determined appropriate to do so, expand our presence in those existing areas. Without any incremental production resulting from our acquisition efforts, any further reduction in our drilling program will adversely affect our future production levels and future cash flow generated from operations. Furthermore, to the extent we are unable to execute our expected drilling program, our return on investment may not be as attractive as we anticipate, and our common stock price may decrease.

We rely on third-party contract operators to drill, complete and manage some of our wells, production platforms, pipelines and processing facilities and, as a result, we have limited control over the daily operations of such equipment and facilities.

We depend upon the services of third-party operators to operate drilling rigs, completion operations, offshore production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our operations are down or our production is shut-in when problems, weather and other production shut-ins occur. Poor performance on the part of, or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition.

Failure of our working interest partners to fund their share of development costs could result in the delay or cancellation of future projects, which could have a materially adverse effect on our financial condition and results of operations.

Our working interest partners must be able to fund their share of investment costs through cash flow from operations, external credit facilities or other sources. If our partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of our reserves and production, or the Company incurring a bad debt charge, which could have a materially adverse effect on our financial condition and results of operations.

We are exposed to the credit risks of our customers, contractual counterparties and derivative counterparties, and any material nonpayment or nonperformance by our customers, contractual counterparties or derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and contractual counterparties, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers and contractual counterparties may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our significant customers or counterparties is in financial distress or commences bankruptcy proceedings, contracts with these customers or counterparties may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us, including pursuant to our current and future joint development agreements, may materially and adversely affect our business, financial condition, results of operations and cash flows.

In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

Repeated offshore production shut-ins can possibly damage our well bores.

Our offshore well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near-term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill a replacement well, which could adversely affect our business, financial condition, results of operations and cash flows.

Oil and natural gas reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future oil and natural gas production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Furthermore, initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Additionally, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

There are numerous uncertainties in estimating oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

In order to prepare these estimates, our internal and independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value. Moreover, failure to meet operating or financial forecasts and expectations, whether published by us or market participants, could adversely impact the trading price of our common stock.

Approximately 20% of our total estimated proved reserves at December 31, 2020 were proved undeveloped reserves. The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our oil, natural gas and natural gas liquids reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated oil, natural gas and natural gas liquids reserves.

You should not assume that the present value of future net revenues from our proved reserves referred to in this report is the current market value of our estimated oil, natural gas and natural gas liquids reserves. In accordance with the requirements of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2020 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2020. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $39.57 per barrel, and the average Henry Hub spot price was $2.14 per MMBtu for natural gas, as prepared by Cobb. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock. Actual future net cash flows will also be affected by increases or decreases in consumption by oil and natural gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from proved reserves. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil, natural gas and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. If exploratory drilling of a prospect, such as the well subject to our joint operating agreement with Juneau, is not successful, we may be required to incur additional expenditures relating to abandonment of the well, with no corresponding revenues. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- abnormal pressure formations, reservoir compaction, surface cratering or uncontrollable flows of underground oil, natural gas or formation water;
- pipe and cement failures, casing collapses, stuck drilling and service tools;
- explosions, fires and blowouts;
- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions and failures;
- unexpected operational events;
- shortages of skilled personnel and regulations or conditions that limit the availability of personnel to operate our business or assets;
- gathering, transportation and processing availability, restrictions or limitations;
- deviations from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- shortages or delivery delays of equipment and services or of water used in hydraulic fracturing activities;
- compliance with environmental and other regulatory requirements;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas so as to minimize emissions of GHGs;
- natural disasters;
- public health crises, such as the COVID-19 pandemic; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, reservoirs, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; suspension of our operations and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance; therefore, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

The potential lack of availability of, or cost of, drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of oil, natural gas and natural gas liquids increase, or the demand for equipment and services is greater than the supply in certain areas, such as the Southern Delaware Basin, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operations and financial condition.

A sustained continuation of product transportation, processing and market constraints in the Southern Delaware Basin may adversely impact our results of operations and the value of our oil and natural gas properties in the region.

The Permian Basin, which includes the Southern Delaware Basin in which we have significant oil and natural gas properties, has been subject to significant product transportation and market constraints resulting from the increased drilling activity and consequent increased production of oil, natural gas and natural gas liquids in the region. One of the results of these constraints over the past several years is the development of significant negative field pricing differentials for Southern Delaware Basin oil, natural gas and natural gas liquids production when compared to prices at major domestic oil and natural gas product hubs. While extensive capital investments are being made to provide additional production transportation, natural gas processing and alternative markets in the region, there is no assurance as to when or if any of these additional midstream and alternative market projects might be made available to our production or at what cost. If these constraints and consequent pricing differentials continue unabated for a significant amount of time, the financial returns for oil and natural gas assets in the Southern Delaware Basin may be considerably devalued when compared to oil and natural gas investments in hydrocarbon producing regions with greater access to major hydrocarbon markets.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, including operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

Further, a blowout, rupture or spill of any magnitude would present serious operational and financial challenges. All of the Company’s operations in the Gulf of Mexico shelf are in water depths of less than 300 feet and less than 50 miles from the coast. Such proximity to the shoreline increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Our ability to market our oil and natural gas may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our oil and natural gas.

All of our oil and natural gas is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

If our access to sales markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory oil, natural gas and natural gas liquids transportation arrangements may hinder our access to oil, natural gas and natural gas liquids markets or delay our production. The availability of a ready market for our oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for and supply of oil, natural gas and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil, natural gas and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in oil and natural gas leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of consultants and others to perform the field work in examining records in the appropriate governmental, county or parish clerk's office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well, the operator of the well will typically obtain a preliminary title review of the drill site lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of oil and natural gas companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive oil and natural gas properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for oil and natural gas and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

We are highly dependent on our senior management team, our exploration partners, third-party consultants and engineers and other key personnel, and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. The loss of key members of our management team or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of oil and natural gas properties or businesses requires an assessment of:

- Recoverable reserves.
- Exploration potential.
- Future oil and natural gas prices.
- Operating costs.
- Potential environmental and other liabilities and other factors.
- Permitting and other authorizations, including environmental permits and authorizations, required for our operations.
- Impact on leverage and access to capital.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.
- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.
- Dilution from issuance of new equity.
- Increased capital commitments or leverage.

We may be unable to integrate the business of Mid-Con or Silvertip successfully or realize the anticipated benefits of each.

On January 21, 2021, we closed the Mid-Con Acquisition, and on February 1, 2021, we completed the Silvertip Acquisition. The combination of multiple independent businesses is complex, costly and time consuming. Potential difficulties that we may encounter as part of the integration process include the following:

- the inability to successfully combine and integrate the businesses of Mid-Con and Silvertip in a manner that permits us to achieve, on a timely basis or at all, the enhanced revenue opportunities and cost savings and other benefits and synergies anticipated to result from the merger; diversion of resources and management attention from our legacy business;
- complexities associated with managing the combined businesses, including difficulty addressing possible differences in operational philosophies and the challenge of integrating complex systems, technology,

networks and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees and other constituencies;

- the assumption of contractual obligations with less favorable or more restrictive terms; and
- potential unknown liabilities and unforeseen increased expenses or delays associated with the merger.

In addition, it is possible that the integration process could result in:

- diversion of the attention of our management; and
- the disruption of, or the loss of momentum in, our ongoing businesses or inconsistencies in standards, controls, procedures and policies.

Any of these issues could adversely affect our ability to maintain relationships with customers, suppliers, employees and other constituencies or achieve the anticipated benefits of the acquisitions, or could reduce our earnings or otherwise adversely affect our business and financial results.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing oil, natural gas and natural gas liquids properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

Cybersecurity breaches and information technology failures could harm our business by increasing our costs and negatively impacting our operations.

We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access or control, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues. Moreover, cybersecurity threat actors, whether internal or external to us, are becoming more sophisticated and coordinated in their attempts to access a Company’s information technology systems and data, including the information technology systems of cloud providers and other third parties with whom companies conduct business.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the controls we have installed have been breached in the past and may be breached in the future, so continuously reviewing, evaluating and enhancing those controls is a priority for our information technology group. During the first quarter of 2020, we were a victim of cyber intrusion, whereby an encryption-based virus was downloaded by third-party hackers into one of the Company's networks. Our information technology team detected the intrusion shortly thereafter and locked down the systems to prevent further intrusion. We reacted quickly by engaging outside experts experienced in dealing with these situations, thereby limiting the extent of intrusion, equipment damage and system downtime. It was ultimately determined that no private information was lost, and that only certain equipment had to be scrubbed of the virus before it could be put back in service. The overall cost of the intrusion event was minimal. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, including key customers and suppliers, could negatively impact our operations in a variety of ways, including but not limited to, the following:

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

- Data corruption, communication interruption or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;

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

- A cyber attack 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;

- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices and reduced revenues;

- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and

- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's or landowner's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Financial Risks

The reduction in the borrowing base under our Credit Agreement, and any further reductions as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our primary sources of liquidity are borrowings under our Credit Agreement and cash from operations. The borrowing base under our Credit Agreement is subject to semi-annual redeterminations which occur on May 1st and November 1st of each year. During a borrowing base redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Agreement. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing our loan, many of which factors are beyond our control. On October 30, 2020, we entered into the Third Amendment to the Credit Agreement, which increased the borrowing base to $130.0 million upon the closing of the Mid-Con Acquisition on January 21, 2021, and which provides that the borrowing base will be automatically reduced by $10 million on March 31, 2021.

The semi-annual redeterminations of our bank borrowing base will occur on May 1st and November 1st of each year. The borrowing base may also be adjusted by certain events, including the incurrence of any senior unsecured debt, material asset dispositions or liquidation of hedges in excess of certain thresholds. Should a determination be made to lower the borrowing base to a level less than our outstanding indebtedness thereunder on the date of such reduction, the excess indebtedness (i.e. a “deficiency”) would exist that we would be required to repay, depending on certain scenarios, either immediately or over a period of six months. Should such a determination be made that creates a deficiency, we may be required to obtain additional capital from monetizing hedges or accessing the capital markets. There is no assurance, however, that we will be able to do so on acceptable terms, if at all. If we are unable to obtain new capital on acceptable terms, we may be unable to operate our producing properties, recommence or implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

If we are unable to comply with restrictions and covenants in our Credit Agreement, there could be a default under the terms of the agreement, which could result in an acceleration of payments of funds that we have borrowed.

Our Credit Agreement contains various affirmative and negative covenants. These negative covenants may limit our ability to, among other things: incur additional indebtedness; make loans to others; make investments; enter into mergers; make or declare dividends or distributions; enter into commodity hedges exceeding a specified percentage of our expected production; enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness; incur liens; sell assets, including any of our oil and natural gas properties, unless we comply with certain conditions; and engage in certain other transactions without the prior consent of the lenders. Our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. We may be required to seek waivers under the Credit Agreement and modifications of covenants, or to reduce our debt by, among other things, reducing our bank borrowing base, issuing equity or completing asset sales and other liquidity-enhancing activities, and these efforts may not be successful. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the Credit Agreement or other agreements governing our indebtedness, an event of default could result, which could permit acceleration of such debt and acceleration of our other debt. Any accelerated debt would become immediately due and payable.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and/or a decline in our oil, natural gas and NGL reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil, natural gas and NGL reserves. We intend to finance our future capital expenditures primarily with cash flow from operations, borrowings under our Credit Agreement and/or proceeds from non-core asset sales, issuances of preferred and common stock (subject to market conditions). Our cash flow from operations and access to capital is subject to a number of variables, including:

- Our proved reserves.
- The level of oil, natural gas and natural gas liquids we are able to produce from existing wells.
- The prices at which oil, natural gas and natural gas liquids are sold.
- Our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our Credit Agreement contains covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base redetermination results in a lower borrowing base under our Credit Agreement, we may be unable to obtain funds otherwise currently available under our Credit Agreement. Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil, natural gas and natural gas liquids reserves.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices and price differentials of oil, natural gas and natural gas liquids, as well as interest rates, we enter into, and may in the future enter into, over-the-counter ("OTC") derivative arrangements for a substantial, but varying portion of our oil, natural gas and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We typically utilize financial instruments to hedge commodity price exposure to declining prices on our oil, natural gas and natural gas liquids production. We typically use a combination of puts, swaps and costless collars.

Our production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

If prices decline, we may incur further impairment of proved properties and experience a reduction in our proved undeveloped reserves.

During the year ended December 31, 2020, we recorded a $164.4 million non-cash charge for proved property impairment of our onshore and offshore properties related to the dramatic decline in commodity prices, the "PV-10" (present value, discounted at a 10% rate) of our proved reserves, and the associated change in our development plans for our proved, undeveloped locations.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and/or natural gas prices continue to remain depressed, we may be required to record additional non-cash impairment write-downs in the future, which would result in a negative impact to our financial results. Furthermore, any sustained decline in oil and/or natural gas prices may require us to make further impairments. We review our proved oil and natural gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded cost basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value.

Management's assumptions used in calculating oil and natural gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment. An impairment may have a material adverse effect on our financial results and the trading price of our common stock.

Increases in interest rates could adversely impact our business, share price and our ability to issue equity or incur debt for acquisitions, capital expenditures or other purposes.

Interest rates may increase in the future. Assuming an outstanding balance on our Credit Agreement of $9.0 million, an increase of one percentage point in the interest rates would have resulted in an increase in interest expense during 2020 of $0.1 million. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Rising interest rates could reduce the amount of cash we generate and materially adversely affect our liquidity. Moreover, the trading price of our common stock is sensitive to changes in interest rates and could be materially adversely affected by any increase in interest rates.

Our indebtedness under our Credit Agreement bears interest at variable interest rates that use the London interbank offered rate ("LIBO Rate") as a benchmark rate. On July 27, 2017, the U.K. Financial Conduct Authority announced that, after the end of 2021, it would no longer persuade or compel contributing banks to make rate submissions to the ICE Benchmark Administration for purposes of the ICE Benchmark Administration setting the London interbank offered rate. Such announcement indicates that the continuation of LIBO Rate on the current basis cannot and will not be assured after 2021, and the LIBO Rate may cease to exist or otherwise be unsuitable for use as a benchmark. Although our Credit Agreement provides a mechanism for determining an alternative rate of interest, such alternative rate may not be similar to, or produce the same value or economic equivalence of, the LIBO Rate or have the same volume or liquidity as did the London interbank offered rate prior to its discontinuance or unavailability. Accordingly, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in or changes to interest rates.

Legal and Regulatory Risks

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in 2010, established federal oversight and regulation of the OTC derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position-limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. In November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions, but the rule was not adopted. In December 2016, the CFTC proposed another new version of the rule, but that too was not adopted. In February 2020, the CFTC proposed another version of its position limits rule that is currently pending at the agency. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing, and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we currently qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps did not qualify for the end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The full impact of the various regulatory requirements will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. In addition, recently, proposals have been made by U.S. banking regulators which, if adopted as proposed, could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. The Dodd-Frank Act and regulations, such as the recently proposed increased capital requirements regulation, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and may continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented to date at the federal level, the EPA and states and groupings of states have considered or pursued cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In particular, the EPA adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified sources in the United

States, including, among others, certain onshore and offshore oil and natural gas production facilities, which includes certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 2016, the EPA published a final rule establishing New Source Performance Standards ("NSPS") Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expanded the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. However, in 2020, the EPA rescinded methane and volatile organic compound emissions standards for new and modified oil and gas transmission and storage infrastructure, as well as methane limits for new and modified oil and gas production and processing equipment. The EPA also relaxed requirements for oil and gas operators to monitor emissions leaks. These amendments are currently being challenged in federal court

Furthermore, in late 2016, the BLM published a final rule to reduce methane emissions by regulating venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the 2016 final rule and codifies the BLM's prior approach to venting and flaring, but this revised rule was vacated by a California federal district court in 2020, a decision which BLM has appealed to the Ninth Circuit Court of Appeals. However, separately, the federal district court of Wyoming vacated the original 2016 rule in October 2020. These rules, should they remain or be placed in effect, and any other new methane emission standards imposed on the oil and natural gas sector could result in increased costs to our operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future international, federal or state laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, which could reduce the demand for the oil and natural gas we produce and lower the value of our reserves, which devaluation could be significant.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and natural gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. It should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. An increase in severe weather patterns could result in damages to or loss of our wells and related facilities, rig availability for drilling new or replacement wells, impact our ability to conduct our production and/or drilling operations and/or result in a disruption of the operations of our customers and service providers. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHGs emissions-related agreements, legislation and measures on our financial performance is highly uncertain because we are unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC or the FTC, we could be subject to substantial penalties and fines.

Section 1(b) of the NGA exempts natural gas gathering facilities from the FERC's jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Our failure to comply with this or other laws and regulations administered by the FERC could subject us to substantial penalties, as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

Under the Energy Policy Act of 2005 and implementing regulations, the FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The CFTC has similar authority under the Commodity Exchange Act and regulations it has promulgated thereunder with respect to certain segments of the physical and futures energy commodities market including oil and natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including oil, condensate and natural gas liquids. These agencies have substantial enforcement authority, including the potential ability to impose maximum penalties for violations in excess of $1 million per day for each violation. Following their adoption, the maximum penalties prescribed by these regulations have been subject to annual adjustment for inflation. The FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. In addition, we rely on our employees, consultants and sub-contractors to conduct our operations in compliance with applicable laws and standards. Our failure, or the failure by such individuals, to comply with these or other laws and regulations administered by these agencies could subject us to substantial penalties, and potential liability as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

We may not be able to utilize a portion of our net operating loss carryforwards ("NOLs") to offset future taxable income for U.S. federal income tax purposes, which could adversely affect our net income and cash flows.

As of December 31, 2018, we had federal net operating loss ("NOL") carryforwards of approximately $365.5 million, approximately $287.3 million of which began to expire in 2018 and will continue to expire in varying amounts through 2037. Utilization of these NOLs depends on many factors, including our future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382 of the Code). An ownership change generally occurs if one or more shareholders (or groups of shareholders) who are each deemed to own at least 5 percent of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change occurs with respect to a corporation following its recognition of an NOL, utilization of such NOL is subject to an annual limitation, generally determined by multiplying the value of the corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. In the case of an NOL that arose in a taxable year beginning before January 1, 2018, any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of such NOL 20 years after it arose.

As a result of our 2019 stock offerings, combined with ownership shifts over the rolling three-year period, we have incurred ownership changes on each of November 19, 2018 and September 12, 2019 pursuant to Section 382, which limits the Company's future ability to use its NOLs. To the extent we are unable to utilize our NOLs to offset future income or carryback our NOLs to apply against prior tax years, we will be limited in use of NOLs for amounts incurred prior to November 20, 2018 in an amount equal to $2.4 million per year (plus any recognized built in gains during the next five years) or until expiration of each annual vintage of NOL (generally, 20 years for each annual vintage of NOLs incurred prior to 2018). However, the September 2019 ownership change resulted in an annual limitation of approximately $700,000 per year, which has the effect of limiting tax attribute usage from the 2018 ownership change in a similar manner and amount. Due to the presence of the valuation allowance from prior years, this event resulted in a no net charge to earnings. Future changes in our stock ownership or future regulatory changes could also limit our ability to utilize our NOLs. To the extent we are not able to offset future taxable income with our NOLs, our net income and cash flows may be adversely affected.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

From time to time, U.S. lawmakers propose certain changes to U.S. tax laws applicable to oil and natural gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes (or the imposition of, or increases in, production, severance or similar taxes) were to be enacted, as well as any similar changes in state, local or non-U.S. law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

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

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing the operation and maintenance of our facilities, the discharge of materials into the environment and environmental protection. Failure to comply with such rules and regulations could result in the assessment of sanctions, including administrative, civil and criminal penalties, investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders limiting or prohibiting some or all of our operations in affected areas. These laws and regulations may require that we obtain permits before commencing drilling or other regulated activities; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and impose substantial penalties for pollution resulting from drilling and production operations. We maintain insurance coverage for sudden and accidental environmental damages; however, it is possible that coverage might not be sufficient in a catastrophic event. Consequently, we could be exposed to liabilities for cleanup costs, natural resource damages and other damages under these laws and regulations, with certain of these legal requirements imposing strict liability for such damages and costs, even though the conduct in pursuing operations was lawful at the time it occurred or the conduct resulting in such damage and costs were caused by prior operators or other third parties.

Environmental laws and regulations in the United States are subject to change in the future, including in connection with the change in federal administration in January 2021, which could result in more stringent legal requirements. If existing environmental regulatory requirements or enforcement policies change or new regulatory or enforcement initiatives are developed and implemented in the future, we may be required to make significant, unanticipated capital and operating expenditures with respect to the continued operations of the drilling program.

Compliance of our operations with these regulations or other laws, regulations and regulatory initiatives, or any other new environmental and occupational health and safety legal requirements could, among other things, require us to install new or modified emission controls on equipment or processes, incur longer permitting timelines, and incur significantly increased capital or operating expenditures, which costs may be significant. Moreover, any failure of our operations to comply with applicable environmental laws and regulations may result in governmental authorities taking actions against us that could adversely impact our operations and financial condition.

An accidental release of pollutants into the environment may cause us to incur significant costs and liabilities.

We may incur significant environmental cost liabilities in our business as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and due to historical industry operations and waste disposal practices. We currently own, operate or lease numerous properties that for many years have been used for the exploration and production of oil and natural gas. Many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. For example, an accidental release resulting from the drilling of a well, could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property and natural resource damages as well as monetary fines or penalties for related violations of environmental laws or regulations. Moreover, certain environmental statutes impose strict, joint and several liability for these costs and liabilities without regard to fault or the legality of our conduct. Under these environmental laws and regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging or other decommissioning activities to prevent future contamination. We may not be able to recover some or any of these costs from insurance.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as activities related to fossil fuel extraction on federal properties, generally, and governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or similar state agencies, but several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the SDWA Underground Injection Control program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The EPA also published final rules under the CAA in 2012 and in 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The BLM also published a final rule in 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in the Ninth Circuit Court of Appeals. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances, including as a result of water withdrawals for fracturing in times or areas of low water availability or due to surface spills during the management of fracturing fluids, chemicals or produced water.

Moreover, from time to time, Congress has considered, but not enacted, legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain states, including Texas and Wyoming, where we conduct operations, have adopted and other states are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. Additionally, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. Some counties have since amended their land use regulations to impose new requirements on oil and natural gas development while other local governments have entered memoranda of agreement with oil and natural gas producers to accomplish the same objective. Hydraulic fracturing operators in Oklahoma have also been subject to lawsuits alleging that their fracturing activities caused a series of earthquakes in the past several years and that these operators are therefore liable for certain damages caused by the earthquakes. Such lawsuits could cause us to incur liabilities for damages caused by earthquakes or otherwise impact the profitability of our operations in Oklahoma.

In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells. Similarly, such impacts could result from new restrictions or prohibitions of oil and gas development activities on federal properties. Expectations or uncertainties regarding such restrictions being imposed (whether through the Executive Branch or by statute) could lead to increased volatility in our business plan and in the market price of our common stock.

We may be subject to additional supplemental bonding under the BOEM financial assurance requirements.

Energy companies conducting oil and natural gas lease operations offshore on the OCS are required by the BSEE, among other obligations, to conduct decommissioning within specified times following cessation of offshore producing activities, which decommissioning includes the plugging of wells, removal of platforms and other facilities and the clearing of obstacles from the lease site sea floor. To cover a lease operator's decommissioning obligations, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or otherwise post bonds or other acceptable financial assurances that such future obligations will be satisfied. As an operator, we are required to post surety bonds of $200,000 per individual lease (or a $1,000,000 area-wide bond) for exploration and $500,000 per lease for developmental activities as part of our general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, our decommissioning obligations. We typically post surety bonds with the BOEM to satisfy our general and supplemental bonding requirements.

The BOEM continues to reconsider the adoption, implementation or enforcement of more stringent financial assurance regulatory initiatives, as well as more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters, all of which could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore on the federal OCS. In particular, the BOEM issued NTL #2016-N01 that became effective in September 2016 and bolsters the financial assurance requirements offshore lessees on the OCS, including the Gulf of Mexico, must satisfy with respect to their decommissioning obligations. If the BOEM determines under NTL #2016-N01 that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. However, in 2017, the Secretary of the U.S. Department of Interior issued Order 3350 ("Order 3350"), which directed the BOEM and the BSEE to reconsider a number of regulatory initiatives governing offshore oil and natural gas safety and performance-related activities, including, for example, NTL #2016-N01, and provide recommendations on whether such regulatory initiatives should continue to be implemented. As a result, the BOEM extended the start date for implementing NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder's decommissioning obligations. In October 2020, BOEM and BSEE proposed a new financial assurance rule which removes certain provisions for third-party guarantees and decommissioning accounts and provides criteria for canceling bonds and third-party guarantees. Overall, the agencies expect the rule to reduce the total amount of financial assurance required. However, this rule is not yet finalized, and until the review is completed and the BOEM determines what additional financial assurance may be required by us, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties.

If we fail to comply with any orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning obligations at those OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee or any subsequent assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees or any subsequent assignee of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

The BSEE has implemented stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. Over the past decade, the agency has been responsible for leading aggressive and comprehensive reforms regarding regulation and oversight of the offshore oil and natural gas industry. These reforms have resulted in more stringent offshore requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. However, as a result of the issuance of Order 3350 in 2017, the BSEE continues to reconsider certain regulations or regulatory initiatives governing offshore oil and natural gas safety and performance-related activities. For example, in December 2017, the BSEE proposed, and in September

2018 it finalized, revisions to its regulations regarding offshore drilling safety equipment, which revisions include the removal of an obligation for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions. Subsequently, on May 2, 2019, BSEE issued the 2019 Well Control Rule, the revised well control and blowout preventer rule governing Outer Continental Shelf (OCS) activities. The new rule revised the then existing regulations impacting offshore oil and natural gas drilling, completions, workovers, and decommissioning activities. Specifically, the 2019 Well Control Rule addresses six areas of offshore operations: well design, well control, casing, cementing, real-time monitoring and subsea containment. The revisions were targeted to ensure safety and environmental protection while correcting errors in the 2016 rule and reducing unnecessary regulatory burden.

Additionally, the Outer Continental Shelf Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspections of all oil and natural gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production and pipeline safety. Upon detecting an alleged violation, the inspector typically issues an Incident of Noncompliance ("INC") to the operator that, depending on the severity of such violation, either serves as a warning to address such violation or requires a shut-in of a facility component or of the entire facility until such time as the violation is corrected. The warning INC is issued for a less severe or threatened condition and must be corrected within a reasonable amount of time, as specified on the INC, whereas the shut-in INC is for more serious conditions that must be corrected before the operator is allowed to resume the activity in question.

In addition to the enforcement actions specified above, the BSEE can assess civil penalties if: (i) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or (ii) the violation resulted in a threat of serious harm or damage to human life or the environment. In January 2018, the BSEE published a final rule that increased the maximum civil penalty rate for Outer Continental Shelf Lands Act violations to $43,576 a day for each violation. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

General Risk Factors

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for and supply of oil, natural gas and natural gas liquids, domestically and globally;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions, domestically and globally;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us, our significant stockholders or members of our management team; and
- natural disasters, pandemics, such as the COVID-19 pandemic, terrorist attacks and acts of war.

Average oil and natural gas prices declined dramatically beginning in early 2015 and have remained relatively low since then, with oil prices reaching historic lows in April 2020 due, in part, to the effects of the COVID-19 pandemic. In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This decline in commodity prices and stock market volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We are a smaller reporting company and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

We are currently a "smaller reporting company" as defined by Rule 12b-2 of the Exchange Act. As a "smaller reporting company," we are subject to reduced disclosure obligations in our SEC filings compared to other issuers, including, among other things, an exemption from the requirement to present five years of selected financial data, being required to provide only two years of audited financial statements in annual reports and being subject to simplified executive compensation disclosures. Until such time as we cease to be a "smaller reporting company," such reduced disclosure in our SEC filings may make it harder for investors to analyze our operating results and financial prospects. If some investors find our common stock less attractive as a result of any choices to reduce disclosure we may make, there may be a less active trading market for our common stock and our stock price may be more volatile.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Also, the provisions of our Credit Agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our board of directors is authorized, without further stockholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. We are authorized to issue up to five million shares of preferred stock. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. Also, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2020, we had 19,847 stock options to purchase shares of our common stock outstanding, all of which were fully vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our bylaws provide certain limitations with respect to business combinations with affiliated stockholders, which may discourage transactions that would otherwise be preferred by a stockholder.

We have elected not to be governed by Texas business combination law, which prohibits a publicly held Texas corporation from engaging in a business combination with an affiliated shareholder for a period of three years after the affiliated shareholder's share acquisition date, unless the business combination is approved in a prescribed manner. Our bylaws, however, provide that, subject to certain exceptions, we shall not engage in any business combination (as defined in our bylaws) with any "affiliated stockholder" for a period of three years following the time that such stockholder became an affiliated stockholder, unless:

- prior to such time, our board of directors approved either the business combination or the transaction which resulted in the stockholder becoming an affiliated stockholder;
- upon consummation of the transaction which resulted in the stockholder becoming an affiliated stockholder, the affiliated stockholder owned at least 85% of our voting common stock outstanding, excluding shares held by certain directors who are also officers;
- at or subsequent to such time, the business combination is approved by the affirmative vote of (i) our board of directors and (ii) the holders of at least two-thirds (2/3) of our outstanding voting common stock not owned by the affiliated stockholder or an affiliate or associate of the affiliated stockholder, at a meeting of stockholders called for that purpose not less than six months after the transaction which resulted in the stockholder becoming an affiliated stockholder; or
- at or subsequent to such time, the business combination is approved by (i) a majority of the directors of our board who are not the affiliated stockholder (or an affiliate or associate thereof, or nominated for election by such affiliated stockholder) and were a member of our board on or prior to June 14, 2019 or were elected or nominated for election by a majority of directors who were members of our board on or prior to June 14, 2019, and (ii) a majority of our voting common stock outstanding.

For purposes of this provision, "affiliated stockholder" means any person that is the owner of 20% or more of the voting common stock outstanding or, during the preceding three-year period, was the owner of 20% or more of our voting common stock outstanding; provided, however, that "affiliated stockholder" does not include certain stockholders whose aggregate ownership does not exceed 23% of our voting common stock outstanding, subject to adjustment by our board of directors. This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. This provision may also have the effect of limiting financing transactions with interested stockholders that could be deemed favorable sources of capital. With the approval of 2/3 of our board of directors or our stockholders, this provision of our bylaws could be amended to further provide antitakeover protection. In addition, with approval of our board of directors and a majority of stockholders, we could change our state of incorporation and modify the antitakeover provisions applicable to us, or we could amend our certificate of incorporation in the future to elect to be governed by the Texas business combination law.

Certain antitakeover provisions may affect your rights as a shareholder.

Our articles of incorporation authorize our board of directors to set the terms of and issue preferred stock without shareholder approval. Our board of directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our Credit Agreement contains terms that may restrict our ability to enter into change of control transactions, including requirements to repay borrowings under our Credit Agreement. These provisions, along with specified provisions of the TBOC and our articles of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

Item 1B. ***Unresolved Staff Comments***

None

Item 2. ***Properties***

As of December 31, 2020, we operated all of our offshore wells, with an average working interest of 54%, and operated 62% of our onshore wells with an average working interest of 76%. As of December 31, 2020, our properties were located in the following regions: Offshore GOM, Central Oklahoma, Western Anadarko, West Texas and Other Onshore.

Development, Exploration and Acquisition Expenditures

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties, exploration costs incurred in the search for new reserves from unproved properties and costs incurred in the development of those properties for the periods indicated (in thousands):

	Year Ended December 31,		
	2020	**2019**	**2018**
Property acquisition costs:			
Unproved	$ 1,508	$ 12,486	$ 10,339
Proved	—	168,838	—
Exploration costs	11,594	1,003	1,637
Development costs	5,819	41,273	42,516
Total costs	$ 18,921	$ 223,600	$ 54,492

Included in unproved property acquisition costs for each of the years ended December 31, 2020, 2019 and 2018 is $0.7 million, $2.7 million and $10.2 million, respectively, related to the acquisition of unproved property in the Southern Delaware Basin of our West Texas region. Unproved property acquisition costs for the year ended December 31, 2019 include $6.0 million related to our offshore Joint Development Agreement with Juneau and $3.1 million related to the properties acquired from Will Energy and White Star.

Included in proved property acquisition costs for the year ended December 31, 2019 are those related to the properties acquired from Will Energy and White Star. See Note 4 – “Acquisitions and Dispositions” for more information.

Included in exploration costs for the year ended December 31, 2020 are $10.5 million related to the drilling of the Iron Flea prospect located in the Grand Isle Block 45 Area in the shallow waters off the Louisiana coastline, which was determined to be unsuccessful in June of 2020. $2.7 million of those exploration expenses are related to acquisition costs incurred in 2019 (and reported as “unproved” costs in the table above) which were reclassified to exploration expense in 2020 as a result of the dry hole.

The decrease in development costs during the year ended December 31, 2020 is related to the suspension of our onshore drilling program in the first quarter of 2020 due to the extreme volatility in oil prices.

The following table presents information regarding our share of the net costs incurred by Exaro in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,		
	2020	**2019**	**2018**
Property acquisition costs	$ —	$ —	$ —
Exploration costs	—	17	—
Development costs	136	72	169
Total costs incurred	$ 136	$ 89	$ 169

Drilling Activity

The following tables show our exploratory and developmental drilling activity for the periods indicated. In the tables, “gross” wells refer to wells in which we have a working interest, and “net” wells refer to gross wells multiplied by our working interest in such wells.

	Year Ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	—	—	—	—	—	—
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	1	0.9	—	—	—	—
Total	1	0.9	—	—	—	—

	Year Ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	1	0.3	7	3.0	8	3.6
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	1	0.3	7	3.0	8	3.6

Exploration and Development Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of oil, natural gas and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres.

The following table shows the approximate developed and undeveloped acreage that we have an interest in, by region, at December 31, 2020.

	Developed Acreage (1)		Undeveloped Acreage (1)	
	Gross	Net (2)	Gross	Net (2)
Offshore GOM	4,213	2,281	—	—
Central Oklahoma	580,480	244,939	48,640	12,744
Western Anadarko	252,800	141,198	21,790	3,274
West Texas	16,248	7,512	—	—
Other Onshore[3]	55,423	31,971	43,671	28,657
Total	909,164	427,901	114,101	44,675

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Net acres represent the number of acres attributable to our proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).
(3) Other Onshore includes acreage in East, South and Southeast Texas, Louisiana, Wyoming and Mississippi.

Some of our onshore leases will expire over the next three years as follows, unless we establish production or take action to extend the terms of these leases:

	Year ending December 31,					
	2021		2022		2023	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Central Oklahoma	42,880	11,072	16,000	1,340	1,280	332
Western Anadarko	21,760	3,232	2,560	42	—	—
West Texas	2,591	1,052	—	—	—	—
Other Onshore	21,369	14,413	2,366	1,744	6,639	5,311
Total	88,600	29,769	20,926	3,126	7,919	5,643

Production, Price and Cost History

The table below sets forth production data, average sales prices and average production costs associated with our sales of oil, natural gas and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2020, 2019 and 2018. Results for the year ended December 31, 2019 include results from the Will Energy Acquisition and White Star Acquisition for the months of November and December only, as those acquisitions were finalized in October 2019. In the first quarter of 2020, we began reporting in barrels of oil equivalents ("Boe") instead of natural gas equivalents. Six thousand cubic feet ("Mcf") of natural gas is the energy equivalent of one barrel of oil, condensate or NGL and is the volumetric conversion factor used herein. Average production costs include lease operating expense, transportation and processing costs and workover costs.

	Year Ended December 31,		
	2020	2019	2018
Production:			
Oil and condensate (thousand barrels)			
Offshore GOM	32	43	73
Central Oklahoma	945	196	—
Western Anadarko	221	42	—
West Texas	303	275	275
Other Onshore	173	235	221
Total oil and condensate	1,674	791	569
Natural gas (million cubic feet)			
Offshore GOM	4,962	5,908	7,704
Central Oklahoma	10,139	1,839	—
Western Anadarko	2,796	552	—
West Texas	208	320	285
Other Onshore	862	904	1,790
Total natural gas	18,967	9,523	9,779
Natural gas liquids (thousand barrels)			
Offshore GOM	127	210	287
Central Oklahoma	851	242	—
Western Anadarko	176	23	—
West Texas	39	64	59
Other Onshore	69	73	128
Total natural gas liquids	1,262	612	474
Total (thousand barrels of oil equivalent)			
Offshore GOM	986	1,237	1,644
Central Oklahoma	3,486	744	—
Western Anadarko	863	157	—
West Texas	377	392	382
Other Onshore	385	460	647
Total production	6,097	2,990	2,673

	Year Ended December 31,		
	2020	2019	2018
Average Sales Price:			
Oil and condensate (per barrel)			
Offshore GOM	$ 37.71	$ 59.68	$ 67.59
Central Oklahoma	38.86	58.95	—
Western Anadarko	32.60	56.58	—
West Texas	36.38	51.36	54.52
Other Onshore	36.48	60.04	65.42
Total weighted average price	$ 37.31	$ 56.55	$ 60.43
Natural gas (per thousand cubic feet)			
Offshore GOM	$ 1.87	$ 2.64	$ 3.14
Central Oklahoma	1.55	1.92	—
Western Anadarko	1.67	1.77	—
West Texas	0.95	0.78	1.87
Other Onshore	1.72	2.21	2.87
Total weighted average price	$ 1.65	$ 2.35	$ 3.05
Natural gas liquids (per barrel)			
Offshore GOM	$ 16.88	$ 17.09	$ 29.48
Central Oklahoma	13.81	14.66	—
Western Anadarko	11.50	11.92	—
West Texas	10.20	14.77	25.55
Other Onshore	10.99	14.57	22.22
Total weighted average price	$ 13.54	$ 15.39	$ 27.04
Total (per barrels of oil equivalent)			
Offshore GOM	$ 12.81	$ 17.58	$ 22.85
Central Oklahoma	18.43	25.05	—
Western Anadarko	16.09	23.11	—
West Texas	30.86	39.06	44.63
Other Onshore	22.17	37.39	34.66
Total weighted average price	$ 18.19	$ 25.59	$ 28.82
Average Production Costs (per barrels of oil equivalent):			
Offshore GOM	$ 5.68	$ 5.13	$ 5.05
Central Oklahoma	12.32	12.42	—
Western Anadarko	9.61	11.32	—
West Texas	9.74	11.13	6.57
Other Onshore	17.22	17.13	18.04
Total weighted average production costs	$ 11.01	$ 9.90	$ 8.41

Productive Wells

Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a “productive” well. The following table sets forth the number of gross and net productive oil and natural gas wells in which we owned an interest as of December 31, 2020:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	7	3.8	—	—
Central Oklahoma	35	4.3	639	338.0
Western Anadarko	281	153.2	119	43.7
West Texas	—	—	18	8.5
Other Onshore	36	20.0	77	46.8
Total	359	181.3	853	437.0

(1) A gross well is a well in which we own an interest.

(2) The number of net wells is the sum of our fractional working interests owned in gross wells.

Oil and Natural Gas Reserves

Estimates of proved reserves and future net revenues were prepared by Cobb and Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum engineering firms, in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE"). Cobb prepared the proved reserves estimates as of December 31, 2020 and 2019 for all of our properties. For the estimates of proved reserves as of December 31, 2018, Cobb prepared the estimates for all of our offshore GOM properties and our onshore West Texas reserves, while NSAI prepared the proved reserves estimates for our remaining onshore properties.

The technical individual at Cobb responsible for overseeing the preparation of our reserve estimates as of December 31, 2020, 2019 and 2018 has over 40 years of experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas, holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a member of the SPE and is a member of the Society of Petroleum Evaluation Engineers. The technical individual at NSAI responsible for the preparation of our reserve estimates as of December 31, 2018 has over 15 years of experience in the estimation and evaluation of reserves, is a licensed professional engineer in the state of Texas, and holds a Bachelor of Science Degree in Petroleum Engineering from the University of Tulsa.

The estimates of proved reserves and future net revenue as of December 31, 2020 and 2019 were reviewed by our corporate reservoir engineering department. The corporate reservoir engineering department interacts with the geoscience, operating, accounting and marketing departments to review the integrity, accuracy and timeliness of the data, and the methods and assumptions used by Cobb and NSAI in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Reservoir Engineering Director is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by our independent petroleum engineering firms. Our Reservoir Engineering Director has a Bachelor of Science degree in Petroleum Engineering from Texas Tech University, is a licensed professional engineer in the state of Texas, has over 15 years of industry experience with positions of increasing responsibility and is a member of the Society of Petroleum Engineers. Reserves are also reviewed internally with senior management and presented to our board of directors in summary form on a quarterly basis.

We maintain adequate and effective internal control over the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of financial data, ownership interests and production data. Our reservoir engineers incorporate material changes in performance, activity and other inputs from operations, geology, land, or other departments, to reserve forecasts on a quarterly basis. The reservoir engineering team shares these changes with our independent petroleum engineering firm annually. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own internal control over financial reporting. Internal control over financial reporting is assessed for effectiveness annually using criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, regional level commodity price differentials, ownership percentages and well production data are updated in the reserve database by our third-party reservoir engineers and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firms prepare their independent reserve estimates and final report.

The following table reflects our estimated proved reserves as of the dates indicated:

	December 31, 2020	December 31, 2019
Crude Oil and Condensate (MBbl) [1]		
Developed	7,166	9,819
Undeveloped	5,838	9,266
Total	13,004	19,085
Natural Gas (MMcf) [1]		
Developed	82,788	122,691
Undeveloped	1,694	8,609
Total	84,482	131,300
Natural Gas Liquids (MBbl) [1]		
Developed	6,595	10,484
Undeveloped	559	1,280
Total	7,154	11,764
Total Mboe		
Developed	27,558	40,752
Undeveloped	6,680	11,979
Total [2]	34,238	52,731
Proved developed reserves percentage	80 %	77 %
Standardized measure *(in thousands)*	$ 115,587	$ 257,842
Prices realized in estimates [3]:		
Crude oil ($/Bbl)	$ 36.57	$ 53.98
Natural gas ($/MMBtu)	$ 1.86	$ 2.17
Natural gas liquids ($/Bbl)	$ 12.43	$ 16.95

(1) Excludes reserves attributable to our 37% equity investment in Exaro.

(2) During the year ended December 31, 2020, total proved reserves decreased by approximately 18.5 MMBoe primarily due to a 21.1 MMBoe decrease related to negative revisions related to commodity prices, a 1.0 MMBoe decrease related to property sales in our Central Oklahoma and Western Anadarko regions and 2020 production of 6.1 MMBoe, partially offset by a 7.5 MMBoe increase related to positive performance revisions primarily in our Central Oklahoma and West Texas regions and a 2.3 MMBoe increase attributable to new PUD locations in our West Texas area.

(3) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per barrel of oil (West Texas Intermediate posted) and per MMBtu (Henry Hub spot) of natural gas. 2020 SEC prices were $39.57 per Bbl of oil and $2.14 per MMBtu of natural gas. 2019 SEC prices were $55.69 per Bbl of oil and $2.52 per MMBtu of natural gas. Prices for natural gas liquids in the table represent average prices for natural gas liquids resulting from the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices were adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves, and those realized prices, as averaged across all proved reserves, are presented in the table.

PV-10

PV-10 at year-end is a non-GAAP financial measure and represents the present value, discounted at 10% per year, of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows represents an estimate of fair market value of our oil and natural gas properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10 (in thousands):

	December 31,	
	2020	2019
Standardized measure of discounted future net cash flows	$ 115,587	$ 257,842
Future income taxes, discounted at 10%	10,789	28,711
Pre-tax net present value, discounted at 10%	$ 126,376	$ 286,553

The following table reflects our estimated proved reserves, by category, as of December 31, 2020 (dollars in thousands):

	Crude Oil and Condensate (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBoe)	% of Total Proved	PV - 10
Proved developed producing	7,162	82,257	6,563	27,434	80 %	$ 111,943
Proved developed non-producing	4	531	32	124	— %	160
Proved undeveloped	5,838	1,694	559	6,680	20 %	14,273
Total	13,004	84,482	7,154	34,238	100 %	$ 126,376

Our estimated net proved reserves as of December 31, 2020, volumetrically, were approximately 38% oil and condensate, 41% natural gas and 21% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves decreased from 40.8 MMBoe at December 31, 2019 to 27.6 MMBoe at December 31, 2020, a decrease primarily attributable to negative revisions related to lower commodity prices of 9.8 MMBoe and 2020 production of 6.1 MMBoe, partially offset by positive performance-related revisions in our Central Oklahoma properties.

The following table presents the changes in our total proved developed reserves for the year ended December 31, 2020:

	Proved Developed Reserves (MBoe)
Proved developed reserves at December 31, 2019	40,752
Extensions, discoveries and other additions	1
Production	(6,097)
Performance revisions [1]	3,254
Pricing revisions [2]	(9,780)
Divestitures	(697)
Conversions & other	125
Proved developed reserves at December 31, 2020	27,558

(1) Performance revisions include 4.6 MMBoe related to our Central Oklahoma properties, which are partially offset by negative revisions related to properties in our other regions.

(2) Pricing revisions include 7.2 MMBoe related to our Central Oklahoma properties and 1.5 MMBoe related to our Western Anadarko properties.

Proved Undeveloped Reserves

Total proved undeveloped reserves ("PUDs") decreased from 12.0 MMBoe at December 31, 2019 to 6.7 MMBoe at December 31, 2020. As noted in the table below, this decrease was primarily attributable to 11.4 MMBoe in negative price-related revisions, partially offset by a 4.3 MMBoe positive performance revision and 2.3 MMBoe of new additions, both of which relate to properties in our West Texas region.

Future drilling plans and timelines are re-evaluated at the end of each calendar year based on updated reserve reports, current drilling cost estimates, production costs and product price forecasts. Our development plan prioritizes reserves based on the capital requirements and the expected incremental net present value to be added. Generally, our plan is to convert PUDs to developed reserves in an order that is based on their economic importance and impact on production and cash flow, but other factors may be considered such as technical merit, product type, location and available working interest partners. The PUD conversion rate in 2020 and 2019 was 52.3% and 6.3%, respectively, of the total net present value of the Company's total PUDs at the beginning of the applicable year after adjusting for respective pricing revisions.

The Company annually reviews any PUDs to ensure their development within five years from the year in which the PUDs were added to proved reserves. The Company's financial resources are expected to be sufficient to drill all of the remaining 6.7 MMBoe of proved undeveloped reserves within the upcoming five-year period. Development costs relating to the 6.7 MMBoe at December 31, 2020 are projected to be approximately $93.1 million over the next five years.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2020:

	Proved Undeveloped Reserves (MBoe)
Proved undeveloped reserves at December 31, 2019	11,979
Extensions, discoveries and other additions [1]	2,328
Performance revisions [2]	4,251
Pricing revisions [3]	(11,362)
Conversion to proved developed	(125)
Divestitures	(257)
Other	(134)
Proved undeveloped reserves at December 31, 2020	6,680

(1) Extensions, discoveries and additions are associated with new PUD locations in our West Texas region.

(2) Performance revisions include 4.1 MMBoe related to our properties in West Texas.

(3) Pricing revisions include 6.6 MMBoe related to our Other Onshore properties and 4.5 MMBoe related to our West Texas properties.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2020, by region, is provided below (excluding reserves attributable to our equity investment in Exaro) (dollars in thousands):

	Proved Reserves				
Regions	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBoe)	PV - 10 [1]
Offshore GOM	161	20,838	557	4,191	$ 9,484
Central Oklahoma	4,241	42,422	4,150	15,461	60,070
Western Anadarko	872	15,664	1,429	4,912	15,765
West Texas	7,189	2,115	729	8,270	34,422
Other Onshore	541	3,443	289	1,404	6,635
Total	13,004	84,482	7,154	34,238	$ 126,376

(1) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per barrel of oil (West Texas Intermediate posted) and per MMBtu (Henry Hub spot) of natural gas. Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices, using SEC rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

While we are reasonably certain of recovering our calculated reserves, the process of estimating oil and natural gas reserves is complex. It requires various assumptions, including oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third-party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

Reserves Attributable to our Equity Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2020 and 2019 for Exaro, which we account for using the equity method, were prepared by Von Gonten in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

The reserves associated with our 37% equity investment in Exaro were prepared by Von Gonten for the years ended December 31, 2020 and 2019. The specific technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2020 and December 31, 2019 has over 18 years of practical experience in the estimation and evaluation of reserves, is a registered professional engineer in the state of Texas, holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University and is a member in good standing of the SPE.

The following table reflects the estimated proved reserves attributable to our equity investment in Exaro:

	December 31, 2020	December 31, 2019
Crude Oil (MBbl)		
Developed	157	225
Undeveloped	—	—
Total	157	225
Natural Gas (MMcf)		
Developed	14,725	21,607
Undeveloped	—	—
Total	14,725	21,607
Total MBoe		
Developed	2,611	3,826
Undeveloped	—	—
Total (3)	2,611	3,826
Proved developed reserves percentage	100 %	100 %
Prices realized in estimates (2)		
Crude oil ($/Bbl)	$ 39.54	$ 55.65
Natural gas ($/MMBtu)	$ 2.03	$ 2.60

(1) The Company's share of the standardized measure of discounted future net cash flows attributable to our equity investment in Exaro does not include the effect of income taxes because Exaro is treated as a partnership for tax purposes. Exaro allocates any income or expense for tax purposes to its partners.

(2) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per barrel of oil (West Texas Intermediate posted) and per MMBtu (Henry Hub spot) of natural gas. All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

(3) During the year ended December 31, 2020, the decrease in Exaro's proved reserves attributable to our investment in Exaro was approximately 1.2 MMBoe.

Item 3. *Legal Proceedings*

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decades-old, poorly documented transactions. Based on prior summary judgments, the trial court entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court’s summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. In early October 2019, the Texas Supreme Court notified the Company that it would not hear this case. The Company engaged additional legal representation to assist in the preparation of an amended petition requesting that the Texas Supreme Court reconsider its initial decision to not review the case. That amended petition was filed, and in mid-March 2020, the Texas Supreme Court decided they would not re-hear the case. Consequently, during the three months ended December 31, 2019, the Company recorded a $6.3 million liability for the judgment, interest and fees, with $3.5 million of such liability related to suspended funds currently reflected in “Accounts payable and accrued liabilities” on the Company’s consolidated balance sheet for the year ended December 31, 2019. The judgment, interest and fees were paid in April 2020.

On January 14, 2016, the Company was named as the defendant in a lawsuit filed in the District Court for Harris County in Texas by a third-party operator. The Company participated in the drilling of a well in 2012, which experienced serious difficulties during the initial drilling, which eventually led to the plugging and abandoning of the wellbore prior to reaching the target depth. In dispute is whether the Company is responsible for the additional costs related to the drilling difficulties and plugging and abandonment. In September 2019, the case went to trial, and, in October 2019, the court ruled in favor of the plaintiff. Prior to the judgment, the Company had approximately $1.1 million in accounts payable related to the disputed costs associated with this case. As a result of the judgment, during the three months ended September 30, 2019, the Company recorded an additional $2.1 million liability for the final judgment plus fees and interest. The Company also prepared and filed an appeal with the appellate court for a review of the initial trial court decision. The plaintiff petitioned the appellate court for an extension of time to file briefs with the court until late in the fourth quarter of 2020. On January 23, 2021, the appellate court notified both parties that it would begin reviewing the merits of the case beginning on February 23, 2021. On March 3, 2021, the appellate court affirmed the trial court’s decision. The Company plans to appeal the decision to the Supreme Court.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

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 common stock is listed on the NYSE American under the symbol "MCF".

As of March 8, 2021, there were approximately 246 registered shareholders of our common stock and no holders of preferred stock.

Holders of common stock are entitled to such dividends as may be declared by the board of directors out of funds legally available. Therefore, any decision to pay future dividends on our common stock will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, capital requirements and other factors our board of directors may deem relevant. We do not anticipate paying any cash dividends on our common stock in the foreseeable future, as we currently intend to retain all future earnings to fund the development and growth of our business. Our Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. The repurchase program does not have an expiration date. No shares were purchased for the years ended December 31, 2020 and 2019. As of December 31, 2020, the Company has $31.8 million available under its share repurchase program, however, those repurchases could be limited under restrictions in the Company's Credit Agreement.

In addition, the Company withheld the following shares, outside of the repurchase program, on a cashless basis from employees as their payment of withholding taxes due on vesting shares of restricted stock previously issued under our stock-based compensation plans:

Period	Total Number of Shares Withheld	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet be Purchased Under Program
October 2020	—	$ —	—	—
November 2020	—	$ —	—	—
December 2020	18,284	$ 2.29	—	—
	18,284	$ 2.29	—	$ 31.8 million

Sale of Unregistered Securities

In November 2020, the Company entered into a purchase agreement with certain purchasers to issue and sell in a private placement 14,193,903 shares of the Company's common stock at a price of $1.55 per Common Share, which resulted in gross proceeds of approximately $22.0 million. The private placement was undertaken in reliance upon an exemption from the registration requirements of the Securities Act, pursuant to Section 4(a)(2) thereof.

In October 2020, the Company entered into a purchase agreement with certain purchasers to issue and sell in a private placement 26,451,988 shares of the Company's common stock at a price of $1.50 per Common Share, which resulted in gross proceeds of approximately $39.7 million. The private placement was undertaken in reliance upon an exemption from the registration requirements of the Securities Act, pursuant to Section 4(a)(2) thereof.

Item 6. ***Selected Financial Data***

As a smaller reporting company as defined by Rule 12b-2 of the Exchange Act, we are not required to provide the information under this item.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

We are a Fort Worth, Texas based independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore properties primarily located in Oklahoma, Texas, Wyoming and Louisiana and use that cash flow to explore, develop, exploit and acquire oil and natural gas properties across the United States.

Impact of the COVID-19 Pandemic

A novel strain of the coronavirus ("COVID-19") surfaced in late 2019 and has spread, and continues to spread, around the world, including to the United States. In March 2020, the World Health Organization declared COVID-19 a pandemic, and the President of the United States declared the COVID-19 pandemic a national emergency. The COVID-19 pandemic has significantly affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the COVID-19 pandemic has resulted in travel restrictions, business closures and other restrictions that have disrupted the demand for oil throughout the world and, when combined with the oil supply increase attributable to the battle for market share among the Organization of Petroleum Exporting Countries ("OPEC"), Russia and other oil producing nations, resulted in oil prices declining significantly beginning in late February 2020. While there has been a modest recovery in oil prices, the length of this demand disruption is unknown, and there is significant uncertainty regarding the long-term impact to global oil demand, which has negatively impacted the Company's results of operations and planned 2020 capital activities. Due to the extreme volatility in oil prices and the impact of COVID-19 on the financial condition of our upstream peers, we suspended our drilling program in the Southern Delaware Basin in the first quarter of 2020 and focused on certain measures that included, but were not limited to, the following:

- work from home initiatives for all but critical staff and the implementation of social distancing measures;
- a company-wide effort to cut costs throughout the Company's operations;
- utilization of the Company's available storage capacity to temporarily store a portion of its production for later sale at higher prices when advantageous to do so (such as the approximate 50,000 barrels of second quarter oil production we stored and sold during the third quarter of 2020 at higher oil prices);
- suspension of any further plans for operated onshore and offshore drilling in 2020;
- pursuit of additional "fee for service" opportunities similar to the Management Services Agreement entered into in June 2020 with Mid-Con Energy Partners, LP ("Mid-Con") (NASDAQ:MCEP), which was terminated at the closing of the Mid-Con Acquisition (as defined below) between the Company and Mid-Con on January 21, 2021; and
- potential acquisitions of PDP-heavy assets, with attractive, discounted valuations, in stressed/distressed scenarios or from non-industry owners, such as our Silvertip Acquisition (as defined below).

From our initial entry into the Southern Delaware Basin in 2016 and through early 2019, we focused on the development of our initial 6,500 net acre position in Pecos County, Texas ("Bullseye"), and in December 2018, we purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of our Bullseye acreage ("NE Bullseye") for approximately $7.5 million. We paid $3.2 million cash in December 2018, with the remaining cash balance paid in installments in March and October of 2019. Our 2019 drilling program in West Texas included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. In December 2019, we began completion operations on the fourth NE Bullseye well, which began producing in January 2020. As of December 31, 2020, we were producing from 18 wells over our approximate 16,200 gross (7,500 net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations.

In response to low commodity prices, and a related window of opportunity to acquire producing properties on very attractive terms, we concluded our 2019 drilling program, which was designed to only preserve core areas of our West Texas play. Thereafter, we focused on identifying, evaluating and acquiring producing reserves. As a result, we were successful in closing the Will Energy Corporation ("Will Energy") and White Star Petroleum, LLC and certain of its affiliates (collectively, "White Star") acquisitions, the ("Will Energy Acquisition" and "White Star Acquisition") in the fourth quarter of 2019. These transactions were transformative, as production from these acquisitions represented approximately 70% of the Company's total net production for the year ended December 31, 2020. See Note 4 – "Acquisitions and Dispositions" for more information.

In connection with the September 2019 signing of the agreement to acquire certain assets from Will Energy and a concurrent equity offering with the White Star Acquisition, we entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the "Credit Agreement"). In connection with the entry into the Credit Agreement, we repaid all obligations outstanding on, and terminated, our previous credit agreement with Royal Bank of Canada, which matured on October 1, 2019. The Credit Agreement has since been amended to increase the number of lenders from three to nine, and among other things, to adjust the borrowing base to $130.0 million on January 21, 2021 and $120.0 million on March 31, 2021. See Note 13 – "Long-Term Debt" for more information.

In December 2019, we entered into a Joint Development Agreement with Juneau Oil & Gas, LLC ("Juneau"), which provides us the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. The first such exploratory prospect acquired by the Company, located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline, was determined to be unsuccessful in June 2020. We are currently evaluating for future testing a number of exploratory prospects included in the Joint Development Agreement, including our Boss Hogg prospect located in the Eugene Island 298 Area in the shallow waters off of the Louisiana coastline. Our strategy and timing on the testing of the Boss Hogg will be determined during the year based on regulatory considerations, some of which are fluid at this time, and on operational considerations, including the availability of appropriate equipment.

On April 10, 2020, we entered into a promissory note evidencing an unsecured loan in the amount of approximately $3.4 million (the "PPP Loan") made to the Company under the Paycheck Protection Program (the "PPP"). The PPP was established under the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act") and is administered by the U.S. Small Business Administration. Under the CARES Act, the PPP Loan may be partially or wholly forgiven following an audit if the funds are used for certain qualifying expenses. We utilized the PPP Loan amount for qualifying expenses during the 24-week coverage period, and on September 30, 2020, submitted our application for forgiveness of all of the PPP Loan in accordance with the terms of the CARES Act and related guidance. We are currently awaiting a response from the Small Business Administration. See Note 13 – "Long-Term Debt" for additional information on the terms of the PPP Loan. We also benefited from certain income tax-related provisions of the CARES Act. See Note 16 – "Income Taxes" for additional information.

On June 5, 2020, we announced the addition of a new corporate strategy that includes offering a property management service (or a "fee for service") for oil and gas companies with distressed or stranded assets, or companies with a desire to reduce administrative costs by engaging a contract operator of its oil and gas assets. As part of this service offering, we entered into a Management Services Agreement ("MSA") with Mid-Con, effective July 1, 2020, to provide services as contract operator of record on Mid-Con's oil and natural gas properties, along with certain administrative and management services, in exchange for an annual services fee of $4 million, paid ratably over the twelve month period, plus reimbursement of certain costs and expenses, a deferred fee of $166,666 per month for each month that the agreement is in effect (not to exceed $2 million), to be paid in a lump sum upon termination of the agreement, and warrants to purchase a minority equity ownership in Mid-Con. In connection with the Company's acquisition of Mid-Con on January 21, 2021, the MSA was terminated, the deferred fee obligation was forgiven, and the warrants were cancelled. See Note 4 – "Acquisitions and Dispositions" for more information. We recorded $2.0 million in revenue during the year ended December 31, 2020 related to this MSA with Mid-Con, which is included in "Fee for services revenue" in the Company's consolidated statements of operations.

On October 25, 2020, we entered into an agreement and plan of merger with Mid-Con providing for the acquisition by the Company of Mid-Con in an all-stock merger transaction in which Mid-Con would become a direct, wholly owned subsidiary of Contango (the "Mid-Con Acquisition"). The Mid-Con Acquisition closed on January 21, 2021, at which time the MSA was terminated. A total of 25,409,164 shares of Contango common stock were issued at the closing of the Mid-Con Acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

Concurrently with the announcement of the Mid-Con Acquisition, we announced the execution of an agreement with a select group of institutional and accredited investors to sell 26,451,988 common shares of the Company. On October 27, 2020, we closed the private placement for net proceeds of approximately $38.8 million, after deducting the underwriting discount and fees and expenses. The use of those proceeds was in connection with the Mid-Con

Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

On November 27, 2020, we entered into a purchase and sale agreement with an undisclosed seller to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico (collectively the "Silvertip Acquisition") for aggregate consideration of approximately $58 million. The Silvertip Acquisition closed on February 1, 2021, for a net consideration of approximately $53.2 million, after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date. See Note 4 – "Acquisitions and Dispositions" for more information.

On December 1, 2020, we completed another private placement of 14,193,903 shares of common stock for net proceeds of approximately $21.7 million, after deducting the underwriting discount and fees and expenses. The net proceeds were used to fund the Silvertip Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

Throughout 2020, we continued to identify opportunities for cost reductions and operating efficiencies in all areas of operations, while also searching for new resource acquisition opportunities. Acquisition efforts have been, and will continue to be, focused on PDP-heavy assets where we might also be able to leverage our geological and operational experience and expertise to reduce operating expenses and enhance production and identify and develop additional drilling opportunities that we believe will enable the Company to economically grow production and add reserves.

For 2021, we believe that a continuing challenging commodity price environment, and a shortage of capital available to the energy industry, may present more opportunities to acquire additional producing properties that could provide strong production, cash flow and future development potential at attractive rates of return. We plan to continue to be active in pursuing such acquisition opportunities and then allowing our technical teams to leverage our experience and expertise to work on increasing returns through cost reduction, production enhancement and future development of the undeveloped drilling locations that come with the production acquired. We can provide no assurances that we will acquire any producing property opportunities on attractive terms, or at all, or that we will realize the expected benefits of any acquisition. We currently have a conservative capital expenditure program planned for 2021 and plan to limit that program to drilling and workover projects that we believe may provide compelling returns in this current commodity price environment, or where necessary, to preserve strategic acreage in our core areas, while simultaneously continuing to make balance sheet strength a priority in 2021 as we utilize excess cash flow to reduce debt and increase our capacity to quickly react to acquisition opportunities.

Our production sales for the year ended December 31, 2020 were approximately 6.1 MMBoe (or 16.7 MBoe/d), comprised of 27% oil, 52% natural gas and 21% NGLs. Our production for the three months ended December 31, 2020 were approximately 1.3 MMBoe (or 14.4 MBoe/d), comprised of 28% oil, 49% natural gas and 23% NGLs. Our onshore properties contributed approximately 82% and 84% of our total production sales for the three and twelve months ended December 31, 2020, respectively.

Revenues and Profitability

Our revenues, profitability and future growth depend substantially on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable, as well as prevailing prices for oil and natural gas.

Reserve Replacement

Generally, producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. Likewise, initial production rates on new wells in the onshore resource plays start out at a relatively high rate with a decline curve which results in 60% to 70% of the ultimate recovery of present value occurring in the first eighteen months of the well's life. We must locate and develop, or acquire, new oil and natural gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and/or acquire oil and natural gas reserves. A prolonged period of depressed commodity prices could have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes in our development plans.

Use of Estimates

The preparation of our financial statements requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include estimates of remaining proved oil, natural gas and NGL reserves, the timing and costs of future drilling and development, estimates of oil, natural gas and NGL revenues, income taxes, stock-based compensation, impairment of oil and natural gas properties, valuation of derivatives, asset retirement obligations, accrued liabilities and purchase price allocations. See "Item 1A. Risk Factors" for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Results of Operations

The table below sets forth our average net daily production sales data in MBoe/d from our regions for each of the periods indicated:

	Three Months Ended							
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020
Offshore GOM	3.9	3.2	3.3	3.2	2.7	2.7	2.8	2.5
Central Oklahoma [(1)(2)]	—	—	—	8.1	10.9	9.1	10.1	8.0
Western Anadarko [(1)(3)]	—	—	—	1.7	2.9	2.5	2.5	1.6
West Texas [(4)]	1.0	1.0	0.9	1.4	1.2	0.9	0.7	1.4
Other Onshore [(5)]	1.1	1.2	1.4	1.3	1.2	0.9	1.1	0.9
	6.0	5.4	5.6	15.7	18.9	16.1	17.2	14.4

(1) Increase in production sales during the three months ended December 31, 2019 due to including November 2019 and December 2019 production from the White Star and Will Energy acquired properties. See Note 4 – "Acquisitions and Dispositions" for more information. Increase in production sales during the three months ended March 31, 2020 due to including a full quarter of production from the White Star and Will Energy acquired properties.

(2) Decrease in production sales during the three months ended June 30, 2020 due to allocating approximately 50,000 Bbls of oil (net to the Company) to inventory storage (0.5 MBoe/d) due to the dramatic decline in crude oil prices. Increase in production sales during the three months ended September 30, 2020 due to the sale of this inventory at improved prices. Decrease in production sales during the three months ended December 31, 2020 primarily due to downtime related to workovers and routine repair and maintenance.

(3) Decrease in production sales during the three months ended December 31, 2020 primarily due to downtime related to weather and routine repair and maintenance.

(4) Increase in production sales during the three months ended December 31, 2019 due to bringing three wells online in our NE Bullseye area. The three months ended December 31, 2020 includes an additional 0.4 MBoe/d due to a reallocation adjustment related to a previous quarter's production.

(5) Includes production from various non-core properties in our South, Southeast and East Texas, Louisiana and Wyoming areas, including properties acquired from White Star and Will Energy.

Non-Core Asset Sales

During the years ended December 31, 2020 and 2019, we completed certain non-core asset sales to enhance our liquidity, eliminate marginal assets and reduce administrative costs. These asset sales provided some immediate liquidity and improved our balance sheet by reducing future asset retirement obligations.

On June 1, 2020, we closed on the sale of certain producing and non-producing properties located in our Central Oklahoma and Western Anadarko regions. These non-core, marginally economic properties were a minor portion of the value of properties acquired from Will Energy and were sold in exchange for the buyer's assumption of the plugging and abandonment liabilities of these properties and revenue held in suspense. We recorded a gain of $4.2 million as a result of the buyer's assumption of the asset retirement obligations associated with the sold properties.

On April 1, 2020, we closed on the sale of certain non-producing properties located in our Central Oklahoma region. These properties were a minor portion of the value of properties acquired from White Star and were sold for approximately $0.5 million in cash. We recorded a gain of $0.2 million as a result of the buyer's assumption of the asset retirement obligations associated with the sold properties.

In June 2019 and July 2019, we sold certain non-core operated assets located in Lavaca and Wharton counties, Texas, and Frio and Zavala counties, Texas, respectively, in exchange for the buyers' assumption of the future plugging and abandonment liabilities associated with the sold properties. We recorded a gain of $0.6 million as a result of these sales.

Year ended December 31, 2020 Compared to Year ended December 31, 2019

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of oil, natural gas and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2020 and 2019 (results for the year ended December 31, 2019 include results from the Will Energy Acquisition and White Star Acquisition for the months of November and December only, as those acquisitions were finalized in October 2019). In the first quarter of 2020, we began reporting in barrels of oil equivalents ("Boe") instead of natural gas equivalents. Six thousand cubic feet ("Mcf") of natural gas is the energy equivalent of one barrel of oil, condensate or NGL and is the volumetric conversion factor used herein. Reported operating expenses include production taxes, such as ad valorem and severance.

	Year Ended December 31,		
	2020	**2019**	**%**
Revenues (thousands):			
Oil and condensate sales	$ 62,461	$ 44,705	40 %
Natural gas sales	31,381	22,380	40 %
NGL sales	17,078	9,427	81 %
Fee for service revenues	2,000	—	100 %
Total revenues	$ 112,920	$ 76,512	48 %
Production:			
Oil and condensate (thousand barrels)			
Offshore GOM	32	43	(26)%
Central Oklahoma	945	196	382 %
Western Anadarko	221	42	426 %
West Texas	303	275	10 %
Other Onshore	173	235	(26)%
Total oil and condensate	1,674	791	112 %
Natural gas (million cubic feet)			
Offshore GOM	4,962	5,908	(16)%
Central Oklahoma	10,139	1,839	451 %
Western Anadarko	2,796	552	407 %
West Texas	208	320	(35)%
Other Onshore	862	904	(5)%
Total natural gas	18,967	9,523	99 %
Natural gas liquids (thousand barrels)			
Offshore GOM	127	210	(40)%
Central Oklahoma	851	242	252 %
Western Anadarko	176	23	665 %
West Texas	39	64	(39)%
Other Onshore	69	73	(5)%
Total natural gas liquids	1,262	612	106 %
Total (thousand barrels of oil equivalent)			
Offshore GOM	986	1,237	(20)%
Central Oklahoma	3,486	744	369 %
Western Anadarko	863	157	450 %
West Texas	377	392	(4)%
Other Onshore	385	460	(16)%
Total production	6,097	2,990	104 %

	Year Ended December 31,		
	2020	2019	%
Daily Production:			
Oil and condensate (thousand barrels per day)			
Offshore GOM	0.1	0.1	— %
Central Oklahoma	2.6	0.5	420 %
Western Anadarko	0.6	0.1	500 %
West Texas	0.8	0.8	— %
Other Onshore	0.5	0.7	(29)%
Total oil and condensate	4.6	2.2	109 %
Natural gas (million cubic feet per day)			
Offshore GOM	13.6	16.2	(16)%
Central Oklahoma	27.7	5.0	454 %
Western Anadarko	7.6	1.5	407 %
West Texas	0.6	0.9	(33)%
Other Onshore	2.3	2.5	(8)%
Total natural gas	51.8	26.1	98 %
Natural gas liquids (thousand barrels per day)			
Offshore GOM	0.3	0.6	(50)%
Central Oklahoma	2.3	0.7	229 %
Western Anadarko	0.5	0.1	400 %
West Texas	0.1	0.2	(50)%
Other Onshore	0.2	0.1	100 %
Total natural gas liquids	3.4	1.7	100 %
Total (thousand barrels of oil equivalent per day)			
Offshore GOM	2.7	3.4	(21)%
Central Oklahoma	9.5	2.0	375 %
Western Anadarko	2.4	0.4	500 %
West Texas	1.0	1.1	(9)%
Other Onshore	1.1	1.3	(15)%
Total production	16.7	8.2	104 %
Average Sales Price:			
Oil and condensate (per barrel)	$ 37.31	$ 56.55	(34)%
Natural gas (per thousand cubic feet)	$ 1.65	$ 2.35	(30)%
Natural gas liquids (per barrel)	$ 13.54	$ 15.39	(12)%
Total (per thousand barrels of oil equivalent)	$ 18.19	$ 25.59	(29)%
Expenses (thousands):			
Operating expenses	$ 72,847	$ 33,205	119 %
Exploration expenses	$ 11,594	$ 1,003	1,056 %
Depreciation, depletion and amortization	$ 30,032	$ 39,807	(25)%
Impairment and abandonment of oil and gas properties	$ 168,802	$ 128,290	32 %
General and administrative expenses	$ 24,940	$ 24,938	0 %
Gain from investment in affiliates (net of taxes)	$ 27	$ 742	(96)%
Other (Income) Expense	$ 30,673	$ (9,587)	(420)%
Selected data per Boe:			
Operating expenses	$ 11.95	$ 11.11	8 %
General and administrative expenses	$ 4.09	$ 8.34	(51)%
Depreciation, depletion and amortization	$ 4.93	$ 13.31	(63)%

Oil, Natural Gas and NGL Sales and Production

Our revenues are primarily from the sale of our oil, natural gas and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. As discussed above, oil prices declined significantly in the first quarter of 2020 as a result of the effects of the COVID-19 pandemic and the ongoing disruptions to the global energy markets and, while there have been modest recoveries of commodity prices, downward pressure on, and volatility in, commodity prices continued through the fourth quarter of 2020. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production from individual wells naturally declines over time as we produce our reserves.

We reported revenues of approximately $112.9 million for the year ended December 31, 2020, compared to revenues of approximately $76.5 million for the year ended December 31, 2019, an increase attributable primarily to the production from the properties acquired from Will Energy and White Star in the fourth quarter of 2019, offset in part by the 29% decrease in the weighted average equivalent sales price period over period. Current year revenues also include $2.0 million related to our fee for service agreement with Mid-Con. Fourth quarter 2020 revenues were $29.2 million, compared to $37.2 million for the 2019 comparative quarter, a decrease attributable to the 17% decrease in in the weighted average equivalent sales price period over period. Our 2020 fourth quarter revenues include $1.0 million related to our fee for service agreement with Mid-Con.

Total production sales for the year ended December 31, 2020 were approximately 6.1 MMBoe (48% liquids), or 16.7 MBoe/d, compared to approximately 3.0 MMBoe (47% liquids), or 8.2 MBoe/d in the prior year, an increase attributable to the production from the properties acquired from Will Energy and White Star. For the fourth quarter of 2020, production sales averaged 14.4 MBoe/d (51% liquids) compared to the 2019 quarter average of 15.7 MBoe/d, (52% liquids) despite the fact that the prior year quarter only included November and December production from the Will Energy and White Star properties acquired in October 2019. The decrease in the current year quarter was primarily attributable to a 0.7 MBoe/d decline from our Gulf of Mexico properties due to the year over year natural decline in production and to downtime related to Hurricane Delta in October 2020.

Net oil production sales were approximately 4,600 barrels per day in 2020 compared to approximately 2,200 barrels per day in 2019, and net oil production sales averaged approximately 4,000 barrels per day in the fourth quarter of 2020 compared to approximately 4,400 barrels per day in the fourth quarter of 2019. The decrease in oil production sales during the current year quarter was primarily related to an approximate 300 barrel per day decrease in our Other Onshore region due to the year over year natural decline in production.

Net NGL production sales were approximately 3,400 barrels per day in 2020 compared to approximately 1,700 barrels per day in 2019, and net NGL production sales averaged approximately 3,300 barrels per day in the fourth quarter of 2020 compared to approximately 3,800 barrels per day in the fourth quarter of 2019. The decrease in NGL production sales during the current year quarter was primarily related to an approximate 500 barrel per day decrease in our Central Oklahoma region due to downtime related to workovers and routine repair and maintenance.

Net natural gas production sales for the year ended December 31, 2020 were approximately 51.8 MMcf/d, compared with approximately 26.1 MMcf/d for the year ended December 31, 2019. For the fourth quarter of 2020, production sales averaged approximately 42.4 MMcf/d compared to the 2019 quarter average of approximately 45.0 MMcf/d. The decline in production sales during the current year quarter was primarily attributable to a 3.1 MMcf/d regional decline from our offshore properties due to natural decline, and to a lesser extent, downtime in October 2020 related to Hurricane Delta.

Average Sales Prices

The average equivalent sales price realized for the years ended December 31, 2020 and 2019 were $18.19 per Boe and $25.59 per Boe, respectively. The decline was attributable to lower realized commodity prices in 2020. The COVID-19 pandemic continued to adversely impact demand for all commodity products, which caused a global supply/demand imbalance for oil that resulted in benchmark oil prices ranging from a high of $63.27 per Bbl at the beginning of 2020 to a low of ($37.63) per Bbl during the second quarter of 2020. The average realized price of oil was $37.31 per Bbl in 2020 compared to an average of $56.55 per Bbl in 2019. Natural gas prices also suffered due to the COVID-19 pandemic, ranging from a low of $1.48 per Mcf to a high of $3.04 per Mcf during 2020. The average realized price of gas was $1.65 per Mcf in 2020 compared to an average of $2.35 per Mcf for 2019, and the average realized price of NGLs was $13.54 per Bbl in 2020 compared to an average of $15.39 per Bbl in 2019.

Operating Expenses (including production taxes)

Total operating expenses for the year ended December 31, 2020 were approximately $72.8 million, or $11.95 per Boe, compared to approximately $33.2 million, or $11.11 per Boe, for the year ended December 31, 2019. The table below provides additional detail of total operating expenses for those periods.

	Twelve Months Ended December 31,			
	2020		2019	
	(in thousands)	(per MBoe)	(in thousands)	(per MBoe)
Lease operating expenses	$ 42,133	$ 6.91	$ 20,644	$ 6.90
Production & ad valorem taxes	5,712	0.94	3,607	1.21
Transportation & processing costs	20,675	3.39	6,085	2.04
Workover costs	4,327	0.71	2,869	0.96
Total operating expenses	$ 72,847	$ 11.95	$ 33,205	$ 11.11

Lease operating expenses were $42.1 million and $20.6 million for the years ended December 31, 2020 and 2019, respectively, an increase due to the addition of our Will Energy and White Star properties acquired in the fourth quarter of 2019. Although lease operating expenses increased year over year, we were able to reduce expenses related to utilities and generators by approximately $3.9 million compared to the prior year, due to our cost savings initiatives implemented in 2020.

Transportation and processing costs were $20.7 million and $6.1 million for the years ended December 31, 2020 and 2019, respectively, an increase due to the addition of our Will Energy and White Star acquired properties and the related higher transportation costs in our Central Oklahoma region.

Exploration Expenses

We reported exploration expense of $11.6 million for the year ended December 31, 2020, compared to the prior year expense of $1.0 million, an increase primarily due to $10.5 million in dry hole costs related to the unsuccessful result on the drilling of the Iron Flea exploratory prospect in the shallow waters of the Grand Isle area of the Gulf of Mexico. Exploration expenses, exclusive of dry hole costs, were primarily related to geological and geophysical software, seismic data licensing fees and mapping services.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expense for the year ended December 31, 2020 was approximately $30.0 million, or $4.93 per Boe, compared to approximately $39.8 million, or $13.31 per Boe, for the year ended December 31, 2019. The lower depletion expense and rate in the current year was related to lower depletable property balances as a result of the proved property impairment recorded during the fourth quarter of 2019 and the first quarter of 2020.

Impairment and Abandonment of Oil and Natural Gas Properties

Impairment and abandonment expenses for the year ended December 31, 2020 included non-cash proved property impairment expense of $164.4 million. During the first quarter of 2020, we recorded a $143.3 million non-cash charge for proved property impairment of our onshore properties related to the dramatic decline in commodity prices, the “PV-10” (present value, discounted at a 10% rate) of our proved reserves, and the associated change in our current development plans for proved, undeveloped locations. In the fourth quarter of 2020, we recorded an additional $21.1 million non-cash charge for proved property impairment, of which $15.6 million related to our offshore properties as a result of performance revisions in reserves and the decline in gas prices and production yield. Under GAAP, we are required to impair the balance sheet carrying cost of our proved property base to reflect that overall decrease in reserve value related to the decrease in prices and the reduction in PUDs.

During the year ended December 31, 2020, we recognized non-cash unproved impairment expense of approximately $4.3 million related to undeveloped leases in our Central Oklahoma, Western Anadarko and Other Onshore regions. We recorded $2.6 million of this impairment expense in the first quarter of 2020, primarily related to leases acquired from White Star and Will Energy in the fourth quarter of 2019, which were expiring in 2020, and we recorded $1.7 million of this impairment expense in the fourth quarter of 2020, due to leases expiring in 2021, all of which we have no plans to extend or develop as a result of the current commodity price environment and our continued focus on cost saving and production enhancing initiatives.

Impairment and abandonment expenses for the year ended December 31, 2019, included non-cash proved property impairment expense of $117.8 million due to reserve revisions which resulted from the negative impact of performance and price related revisions to the present value of our year-end proved reserves, and the relationship of that value to the historical carrying cost of our assets on the balance sheet. Included in the impairment charge was $34.5 million related to our proved offshore Gulf of Mexico properties, primarily a result of performance revisions associated with the re-evaluation of the projected field costs and recoverable condensate volumes. In addition, we recognized onshore proved property impairment expense of $83.3 million, due primarily to price and performance revisions, which led to the re-evaluation of the economics and future drilling plans for the proved undeveloped locations, which then resulted in the elimination of certain proved undeveloped locations due to the SEC's five-year development rule for such locations.

During the year ended December 31, 2019, we recognized non-cash unproved impairment expense of approximately $9.2 million related primarily to lease expirations, and near-term expirations, in the Bullseye portion of our West Texas area.

General and Administrative Expenses

Total general and administrative expenses for the years ended December 31, 2020 and 2019 were approximately $24.9 million.

The table below provides additional detail of general and administrative expenses for each of the twelve-month periods:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Wages, bonuses and employee benefits (1)	$ 12,584	5,059
Non-cash stock-based compensation (1)	4,270	2,352
Professional fees (2)	5,543	5,080
Professional fees - special (3)	4,380	4,177
Legal judgments (4)	(560)	4,973
Recouped Overhead (5)	(12,682)	(1,104)
Other (6)	10,129	4,392
Allowance for doubtful accounts (7)	1,276	9
Total general and administrative expenses	$ 24,940	$ 24,938

(1) Higher expenses for the year ended December 31, 2020 due to the acquisition of certain Will Energy and White Star employees in the fourth quarter of 2019, as well as the acquisition of certain Mid-Con employees in the third quarter of 2020 in connection with the MSA.
(2) Primarily includes fees related to recurring legal counsel, technical consultants and accounting and auditing costs.
(3) Non-recurring fees incurred in conjunction with our pursuit of strategic initiatives, such as our recently closed Mid-Con Acquisition, and expenses associated with the acquisition and integration of the White Star and Will Energy assets acquired during the three months ended December 31, 2019. See Note 4 – "Acquisitions and Dispositions" and Note 17 – "Subsequent Events" for further details.
(4) The current year credits are related to reimbursements of legal fees for settled legal judgments. The prior year expense includes an accrual for a judgment received in 2019. See Note 14 – "Commitments and Contingencies" for further details.
(5) These credits relate to overhead we are able to bill out to partners in our operated properties and offset against our other general and administrative costs. The increase in the current year credit is due to the additional overhead related to the acquired Will Energy and White Star properties.
(6) Increase due to additional expenses related to the acquired Will Energy and White Star properties, offices and employees primarily related to IT, insurance and office costs such as rent, equipment and supplies.
(7) The increase in the current year allowance for doubtful accounts expense is primarily due to the additional properties acquired from Will Energy and White Star.

Gain from Affiliates

For the year ended December 31, 2020 and 2019, we recorded a gain from affiliates of approximately $27,000, net of zero expense, and a gain of approximately $1.0 million, net of zero tax expense, respectively, related to our equity investment in Exaro.

Gain on Derivatives

During the year ended December 31, 2020, we recorded a gain on derivatives of $27.6 million. Of this amount, $2.3 million were non-cash, unrealized mark-to-market gains as commodity prices declined from 2019 year-end levels, and $25.3 million were realized gains on derivative contracts settled each month during the period. During the year ended December 31, 2019, we recorded a loss on derivatives of $3.4 million. Of this amount, $6.0 million were non-cash, unrealized mark-to-market losses, and $2.6 million were realized gains on derivative contracts settled each month during the period.

Capital Resources and Liquidity

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our Credit Agreement.

During the year ended December 31, 2020, we incurred onshore expenditures of approximately $7.3 million on capital projects, including $3.7 million in the Southern Delaware Basin to bring one well on production and drill a salt water disposal well with associated facilities and $0.7 million in leasehold acquisition costs in the region. The remaining onshore capital expenditures incurred related primarily to capitalized workovers.

During the year ended December 31, 2020, we recorded an exploration expense of $10.5 million related to the drilling of the unsuccessful exploratory Iron Flea prospect drilled in the shallow waters of the Gulf of Mexico. Approximately $2.7 million of the exploration expense was prospect acquisition costs incurred in 2019 which were reclassified to exploration expense in 2020 as a result of the dry hole.

On June 24, 2020, we entered into an Open Market Sale Agreement (the “Sale Agreement”) among the Company and Jefferies LLC (the “Sales Agent”). Pursuant to the terms of the Sale Agreement, we may sell, from time to time through the Sales Agent in the open market, subject to satisfaction of certain conditions, shares of the Company’s common stock, having an aggregate public offering price of up to $100,000,000 (the “Shares”) (the “ATM Program”). We intend to use the net proceeds from any sales through the ATM Program, after deducting the Sales Agent’s commission and any offering expenses, to repay borrowings under our Credit Agreement and for general corporate purposes, including, but not limited to, acquisitions and exploratory drilling. Under the ATM Program, we sold 163,929 shares during the year ended December 31, 2020 for net proceeds of $0.5 million.

On October 25, 2020, we entered into an agreement and plan of merger with Mid-Con in an all-stock merger transaction in which Mid-Con would become a direct, wholly owned subsidiary of Contango. The Mid-Con Acquisition closed on January 21, 2021, at which time the MSA was terminated. A total of 25,409,164 shares of Contango common stock were issued at the closing of the Mid-Con Acquisition. See Note 4 – “Acquisitions and Dispositions” for further details.

On October 27, 2020, we completed a private placement of 26,451,988 shares of common stock with a select group of institutional and accredited investors for net proceeds of approximately $38.8 million, after deducting the underwriting discount and fees and expenses. The use of those proceeds was in connection with the Mid-Con Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

On November 27, 2020, we entered into a purchase and sale agreement with an undisclosed seller to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico for aggregate consideration of approximately $58 million in cash, subject to customary closing adjustments. In connection with the execution of the Purchase Agreement, we paid $7.0 million as a deposit for our obligations under the Purchase Agreement, which is included in “Deposits” on the Company’s consolidated balance sheet as of December 31, 2020. The Silvertip Acquisition closed on February 1, 2021, and a balance of $46.2 million was paid upon closing of the Silvertip Acquisition, after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date. See Note 4 – “Acquisitions and Dispositions” for more information.

On December 1, 2020, we completed another private placement of 14,193,903 shares of common stock for net proceeds of approximately $21.7 million, after deducting the underwriting discount and fees and expenses. The net proceeds were used to fund the Silvertip Acquisition and for general corporate purposes, including the repayment of debt outstanding under our Credit Agreement.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the periods indicated, in thousands.

	Year ended December 31, 2020	Year ended December 31, 2019
Net cash provided by operating activities	$ 20,896	$ 21,710
Net cash used in investing activities	$ (21,353)	$ (154,855)
Net cash provided by financing activities	$ 216	$ 134,769
Cash and cash equivalents at the end of the period	$ 1,383	$ 1,624

Cash flow from operating activities, including changes in working capital, provided approximately $20.9 million in cash for the year ended December 31, 2020 compared to $21.7 million for the year ended December 31, 2019. Cash flow from operating activities, excluding changes in working capital, provided approximately $42.9 million in cash for the year ended December 31, 2020 compared to $14.6 million for the year ended December 31, 2019. Cash used for changes in working capital were approximately $22.0 million during 2020, compared to $7.1 million in cash provided due to changes in working capital during 2019. Included in 2020 activity is a $7.0 million deposit paid towards the Silvertip Acquisition during the three months ended December 31, 2020.

Net cash flows used in investing activities were $21.4 million for the year ended December 31, 2020, which was primarily related to the offshore exploratory prospect and completion and infrastructure costs in the Southern Delaware Basin.

Net cash flows used in investing activities were $154.9 million for the year ended December 31, 2019, which included $112.1 million in cash for the Will Energy Acquisition and White Star Acquisition and the Joint Development Agreement with Juneau. Additionally, we expended $42.8 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and non-operated wells in the Georgetown formation.

Cash flows provided by financing activities were approximately $0.2 million for the year ended December 31, 2020 compared to $134.8 million provided by financing activities in 2019. Included in 2020 activity was $60.9 million in total net proceeds from equity offerings, $63.8 million repayment of amounts outstanding under our Credit Agreement and approximately $3.4 million related to proceeds from the PPP loan we received under the CARES Act in April 2020. See "Paycheck Protection Program Loan" below for more information. Included in 2019 activity was $125.7 million in total net proceeds from equity offerings, $60.0 million in repayment of all outstanding borrowings under our prior credit agreement in conjunction with the termination of our previous credit facility in September 2019 and $72.8 million in net borrowings under our current Credit Agreement.

Credit Agreement

On September 17, 2019, we entered into a new revolving credit agreement with JPMorgan Chase Bank, which established a borrowing base of $65 million. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the property acquisitions from Will Energy and White Star, to add two additional lenders and increase the borrowing base thereunder to $145 million. The borrowing base is subject to semi-annual redeterminations and may also be adjusted by certain events, including the incurrence of any senior unsecured debt, material asset dispositions or liquidation of hedges in excess of certain thresholds. The semi-annual redeterminations will occur on or around May 1st and November 1st of each year. On June 9, 2020, we entered into the Second Amendment to the Credit Agreement (the "Second Amendment"). The Second Amendment redetermined the borrowing base at $95 million pursuant to the regularly scheduled redetermination process, with further $10 million automatic reductions in our borrowing base on each of June 30, 2020 and September 30, 2020. Additionally, the Second Amendment provides for, among other things, the implementation of an accounts payable aging reporting covenant, and the implementation of typical anti-cash hoarding provisions and a cash sweep requirement, in certain circumstances, with respect to a consolidated cash balance in excess of $5.0 million. On October 30, 2020, we entered into the Third Amendment to the Credit Agreement (the "Third Amendment"), which became effective on January 21, 2021, upon the satisfaction of certain conditions, including the closing of the Mid-Con Acquisition. As of December 31, 2020, the borrowing base was $75 million; however, upon the January 21, 2021 effectiveness of the Third Amendment, the borrowing base increased to $130.0 million with a scheduled $10.0 million automatic stepdown in borrowing base on March 31, 2021. The next regularly scheduled borrowing base redetermination is on or before May 1, 2021. See Note 13 – "Long-Term Debt" for more information.

The Credit Agreement matures on September 17, 2024. The Credit Agreement contains customary and typical restrictive covenants. The Credit Agreement requires a Current Ratio of greater than or equal to 1.00 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Agreement. The Second Amendment includes a waiver of the Current Ratio requirement until the quarter ending March 31, 2022. As of December 31, 2020, we were in compliance with all financial covenants under the Credit Agreement.

As of December 31, 2020, the borrowing outstanding under the Credit Agreement was $9.0 million and $1.9 million in an outstanding letter of credit, and the borrowing availability under the Credit Agreement was $64.1 million.

Paycheck Protection Program Loan

On April 10, 2020, we entered into a promissory note evidencing an unsecured loan in the amount of approximately $3.4 million (the "PPP Loan") made to the Company under the Paycheck Protection Program (the "PPP"). The PPP was established under the Coronavirus Aid, Relief, and Economic Security Act ("CARES Act"), signed into law on March 27, 2020, and is administered by the U.S. Small Business Administration. The PPP Loan to the Company is being made through JPMorgan Chase Bank, N.A and is included in "Long-Term Debt" on the Company's consolidated balance sheet.

The PPP Loan matures on the two-year anniversary of the funding date and bears interest at a fixed rate of 1.00% per annum. Monthly principal and interest payments, less the amount of any potential forgiveness (discussed below), will commence after the six-month anniversary of the funding date. The promissory note evidencing the PPP Loan provides for customary events of default, including, among others, those relating to failure to make payment, bankruptcy, breaches of representations and material adverse effects. We may prepay the principal of the PPP Loan at any time without incurring any prepayment charges.

Under the terms of the CARES Act, PPP loan recipients can apply for and be granted forgiveness for all or a portion of the loans granted under the PPP, subject to an audit. Under the CARES Act, loan forgiveness is available, subject to limitations, for the sum of documented payroll costs, covered mortgage interest payments, covered rent payments and covered utilities during either: (1) the eight-week period beginning on the funding date; or (2) the 24-week period beginning on the funding date. Forgiveness is reduced if full-time employee headcount declines, or if salaries and wages for employees with salaries of $100,000 or less annually are reduced by more than 25%. We utilized the PPP Loan amount for qualifying expenses during the 24-week coverage period, and on September 30, 2020, submitted our application for forgiveness of all of the PPP Loan in accordance with the terms of the CARES Act and related guidance. We are currently waiting on a response from the Small Business Administration. In the event the PPP Loan or any portion thereof is forgiven, the amount forgiven is applied to the outstanding principal.

Future Capital Requirements

Our future oil, natural gas and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We anticipate that acquisitions, including those of undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities arise from time to time; however, there can be no assurance that we will be successful in consummating any acquisitions, or that any such acquisition entered into will be successful. These potential acquisitions are not part of our current capital budget and would require additional capital. Oil and natural gas prices continue to be volatile, and our financial resources may be insufficient to fund any of these opportunities. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that our internally generated cash flow and proceeds from the sale of non-core assets, combined with availability under our Credit Agreement will be sufficient to meet the liquidity requirements necessary to fund our daily operations and planned capital development and to meet our debt service requirements for the next twelve months. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors.

Our 2021 capital budget will be focused primarily on: (i) preserving our financial position, including limiting capital expenditures to internally generated cash flow and proceeds from the sale of non-core assets; (ii) focusing drilling expenditures on strategic projects that provide good investment returns in the current price environment; and (iii) identifying opportunities for cost efficiencies in all areas of our operations. Our 2021 capital expenditure budget is currently planned to be between $13 - $16 million for capital workovers, facility upgrades, waterflood development and selected new well drills; however, due to our ongoing evaluation of future development for our recently acquired properties from the Mid-Con Acquisition and the Silvertip Acquisition, and the regulatory and operational considerations to consider in our GOM program, our capital expenditure program will continue to be evaluated for revision during the year. We believe that we will have the financial resources to increase the currently planned 2021 capital expenditure budget, when and if deemed appropriate, including as a result of changes in commodity prices, economic conditions or operational factors.

Our current capital budget for 2021 should allow us to meet our contractual requirements and remain in position to preserve our term acreage where appropriate during this challenging period for our industry. We will continuously monitor the commodity price environment and economic conditions, and if warranted, make adjustments to our investment strategy as the year progresses.

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the energy industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have, a material effect on our operations; however, we cannot predict these fluctuations.

Income Taxes

During the year ended December 31, 2020, we paid approximately $0.3 million in state income taxes and no federal income taxes. During the year ended December 31, 2019, we paid approximately $0.7 million in state income taxes and no federal income taxes.

Application of Critical Accounting Policies and Management’s Estimates

The discussion and analysis of the Company’s financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company’s significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to oil and natural gas reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third-party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company’s consolidated financial statements:

Oil and Natural Gas Properties - Successful Efforts

Our application of the successful efforts method of accounting for our oil and natural gas exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive oil and natural gas field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Reserve Estimates

While we are reasonably certain of recovering our reported reserves, the Company's estimates of oil and natural gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating producible underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future development costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and natural gas properties and/or the rate of depletion of such oil and natural gas properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Impairment of Oil and Natural Gas Properties

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. An impairment loss associated with an asset group is the amount by which the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. An asset's fair value is preferably indicated by a quoted market price in the asset's principal market. Unlike many businesses where independent appraisals can be obtained for items such as equipment, oil and natural gas proved reserves are unique assets. Most oil and natural gas valuations are based on a combination of the income approach and market approach methodologies. We utilize the income approach also known as the discounted cash flow ("DCF") approach. Under the DCF method in determining fair value, there are specific guidelines and ranges within the evaluation that we can consider and estimate.

The Company compares expected undiscounted future net cash flows on a field basis to the unamortized capitalized cost of the assets in that field. If the future undiscounted net cash flows, based on the Company's estimate of future oil and natural gas prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Drilling activities in an area by other companies may also effectively impair leasehold positions. Given the complexities associated with oil and natural gas reserve estimates and the history of price volatility in the oil and natural gas markets, events may arise that will require the Company to record an impairment of its oil and natural gas properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Derivative Instruments

The Company elected to not designate any of its derivative positions for hedge accounting. At the end of each reporting period, we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives, along with the realized gain or loss for settled derivatives, is reported in "Other Income (Expense)" as "Gain (loss) on derivatives, net".

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Accounting for uncertainty in income taxes prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2020, we had federal net operating loss ("NOL") carryforwards of $404.7 million. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Internal Revenue Code Section 382 related to changes of more than 50% of ownership of the Company's stock by 5% or greater shareholders over a three-year period (a Section 382 Ownership Change) from the time of such an ownership change. The Company experienced two separate Section 382 Ownership Changes in connection with two of its equity offerings occurring in 2018 and 2019, respectively (the "Ownership Changes"). Market conditions at the time of the 2019 Ownership Change had diminished from the time of the 2018 Ownership Change, thus subjecting virtually all of the Company's tax attributes to an annual limitation of $0.7 million a year (in pre-tax dollars). This lower annual limitation resulting from the 2019 Ownership Change effectively eliminates the ability to utilize these tax attributes in the future. Given our annual Section 382 limitation and the uncertainty of our ability to generate taxable income, a valuation allowance of $145.3 million has been recorded for the year ended December 31, 2020 against the deferred tax assets, reduced by the amount of the deferred tax liability.

Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. See Note 16 – "Income Taxes" to our consolidated financial statements.

Properties Acquired in Business Combinations

When sufficient market data is not available, we determine the fair values of proved and unproved oil and natural gas properties acquired in transactions accounted for as business combinations by preparing estimates of cash flows from the production of crude oil, natural gas and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. When estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors. For other assets acquired in business combinations, we use a combination of available cost and market data and/or estimated cash flows to determine the fair values

Recent Accounting Pronouncements

In June 2016, the FASB issued ASU 2016-13 - Financial Instruments - Credit Losses ("Topic 326"): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including the Company's trade and joint interest billing receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date that is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model that increases the allowance when losses are probable. Initially, ASU 2016-13 was effective for all public companies for fiscal years beginning after December 15, 2019. The FASB subsequently issued ASU 2019-04 ("ASU 2019-04"): Codification Improvements to Topic 326, Financial Instruments - Credit Losses, Topic 815, Derivatives, and Topic 825, Financial Instruments and ASU 2019-05 ("ASU 2019-05"): Financial Instruments - Credit Losses (Topic 326) - Targeted Transition Relief. ASU 2019-04 and ASU 2019-05 provide certain codification improvements related to the implementation of ASU 2016-13 and targeted transition relief consisting of an option to irrevocably elect the fair value option for eligible instruments. In November 2019, the FASB issued ASU 2019-10 - Financial Instruments - Credit Losses (Topic 326), Derivatives and Hedging

(Topic 815), and Leases (Topic 842): Effective Dates. This amendment deferred the effective date of ASU 2016-13 from January 1, 2020 to January 1, 2023 for calendar year-end smaller reporting companies, which includes the Company. The Company plans to defer the implementation of ASU 2016-13, and the related updates.

In November 2019, the FASB issued ASU 2019-12 - Income Taxes ("Topic 740"): Simplifying the Accounting for Income Taxes ("ASU 2019-12"). The amendments in ASU 2019-12 are part of an initiative to reduce complexity in accounting standards and simplify the accounting for income taxes by removing certain exceptions from Topic 740 and making minor improvements to the codification. The amendments in this update are effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The provisions of this update are not expected to have a material impact on the Company's financial position or results of operations.

In March 2020, the FASB issued ASU 2020-04 - Reference Rate Reform ("Topic 848"): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("ASU 2020-04"). ASU 2020-04 provides optional guidance, for a limited period of time, to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. The amendments in ASU 2020-04 provide optional expedients and exceptions for applying US GAAP to contracts, hedging relationships and other transactions affected by reference rate reform if certain criteria are met. The amendments in this ASU apply only to contracts, hedging relationships and other transactions that reference LIBOR, or another reference rate, expected to be discontinued because of reference rate reform. The Company is currently assessing the potential impact of ASU 2020-04 on its consolidated financial statements.

Off Balance Sheet Arrangements

We may from time to time enter into short-term off-balance sheet arrangements that can give rise to off-balance sheet obligations, such as short-term drilling rig contracts and operating lease agreements, all of which are customary in the oil and natural gas industry. Other than the off-balance sheet delay rental arrangements included in the commitments and contingencies table under Note 14 – "Commitments and Contingencies", we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources as of December 31, 2020.

Item 8. ***Financial Statements and Supplementary Data***

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-43 of this Form 10-K.

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

An evaluation was performed under the supervision and with the participation of the Company's senior management, including the Company's Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") as of December 31, 2020, the end of the period covered by this report. Based on that evaluation, the Company's management, including the Chief Executive Officer and the Chief Financial Officer, concluded that the Company's disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to the Company's management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

As noted under "*Management's report on internal control over financial reporting*", management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting included those internal controls associated with the integration of the assets acquired from Will Energy on October 25, 2019 and White Star on November 1, 2019. As a result of these integration activities, certain controls have been evaluated and revised where deemed appropriate. Other than such changes, there was no change in our internal control over financial reporting during the fiscal quarter ended December 31, 2020 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *2013 Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in *2013 Internal Control-Integrated Framework*, the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2020. Management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting included the integration of the operating results of the assets acquired from Will Energy and White Star during the three months ended December 31, 2019.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2021 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Proposal 1: Election of Directors", "Executive Compensation", "Delinquent Section 16(a) Reports" (if necessary) and "Corporate Governance and our Board" and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after December 31, 2020.

Code of Ethics

In January 2014, our board of directors adopted our current Code of Business Conduct and Ethics ("Code of Conduct") which applies to all directors, officers and employees of the Company, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Conduct is available on the Company's website at www.contango.com. Changes in and waivers to the Code of Conduct for the Company's directors, chief executive officer and certain senior financial officers will be posted on the Company's website within four business days and maintained for at least 12 months, to the extent required. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

Item 11. ***Executive Compensation***

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Other than as set forth below, the information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

Securities authorized for issuance under equity compensation plans

The following table sets forth information about our equity compensation plans at December 31, 2020:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights [1]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
Second Amended and Restated 2009 Incentive Compensation Plan	2,846,140 [2]	$ —	6,240,312
Equity plans not approved by security holders			
2005 Stock Incentive Plan ("Crimson Plan")	19,847	$ 59.62	—

(1) The weighted-average exercise price does not take into account the shares issuable upon vesting of outstanding performance stock units, which have no exercise price.

(2) Represents shares issuable upon the vesting of performance stock units awarded under the plan. The actual number of shares that a grant recipient receives at the end of the period may range from 0% to 300% of the target number of shares.

The 2005 Stock Incentive Plan was adopted by our Board in conjunction with the merger with Crimson Exploration, Inc. (“Crimson”). Prior to such merger, it had been approved by Crimson stockholders. The plan expired on February 25, 2015, and therefore no additional shares are available for grant.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the headings “Corporate Governance and our Board”, “Transactions with Related Persons” and “Executive Compensation” and is incorporated herein by reference.

Item 14. *Principal Accountant Fees and Services*

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the subheading “Principal Accountant Fees and Services” and is incorporated herein by reference.

GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

2D seismic or *3D seismic.* Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

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

Bcf. Billion cubic feet of natural gas.

Boe. Barrel of oil equivalent per day determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

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

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

IP 30. The average daily hydrocarbon production rate of the initial 30 days of full commercial production. IP 30 average daily production rates are subject to natural and mechanical declines and are accordingly not comparable to the average daily production rate over the life of the well.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil or other liquid hydrocarbons equivalent.

MBoe/d. MBoe per day.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil or other liquid hydrocarbons equivalent.

MMBoe/d. MMBoe per day.

MMBtu. Million British Thermal Units. One MMBtu equates to approximately one Mcf.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed producing reserves. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, which defines proved developed reserves as reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as the estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

The area of a reservoir considered proved includes (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and natural gas on the basis of available geological and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geological, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and the project has been approved for development by all necessary parties and entities, including governmental entities.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. A non-GAAP financial measure that represents the present value, discounted at 10% per year, of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows represents an estimate of fair market value of oil and natural gas properties. PV-10 is used by the industry as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

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

Total Measured Depth or TMD. The total measured drilled vertical and horizontal depth of a well.

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

Unbooked Locations. Internal estimates based on the Company’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources.

Working interest or WI. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) Financial Statements and Schedules:

The financial statements are set forth in pages F-1 to F-43 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated October 25, 2020, by and among Contango Oil & Gas Company, Michael Merger Sub LLC, Mid-Con Energy Partners, LP, and Mid-Con Energy GP, LLC (filed as Exhibit 2.1 to the Company's Report on Form 8-K/A dated October 25, 2020, as filed with the Securities and Exchange Commission on October 27, 2020 and incorporated by reference herein).
2.2	Asset Purchase and Sale Agreement, dated as of November 27, 2020, among Contango Oil & Gas Company, as purchaser, and Grizzly Operating, LLC, as seller thereto). **†**
3.1	Amended and Restated Certificate of Formation of Contango Oil & Gas Company (filed as Exhibit 3.3 to the Company's Report on Form 8-K dated June 14, 2019, as filed with the Securities and Exchange Commission on June 14, 2019 and incorporated by reference herein).
3.2	Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.4 to the Company's Report on Form 8-K dated June 14, 2019, as filed with the Securities and Exchange Commission on June 14, 2019 and incorporated by reference herein).
3.3	Statement of Resolution Establishing Series of Shares Designated Series A Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
3.4	Statement of Resolution Establishing Series of Shares Designated Series B Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
3.5	Certificate of Amendment to the Amended and Restated Certificate of Formation of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated December 12, 2019, as filed with the Securities and Exchange Commission on December 16, 2019 and incorporated by reference herein).
3.6	Statement of Resolution Establishing Series of Shares Designated Series C Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated December 19, 2019, as filed with the Securities and Exchange Commission on December 23, 2019 and incorporated by reference herein).
3.7	Certificate of Amendment to the Amended and Restated Certificate of Formation of Contango Oil & Gas Company, dated June 10, 2020 (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated June 11, 2020, as filed with the Securities and Exchange Commission on June 11, 2020 and incorporated by reference herein).
4.1	Description of Securities registered under Section 12 of the Exchange Act. †
10.1*	Amended and Restated 2005 Stock Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated as of October 1, 2013, as filed with the Securities and Exchange Commission on October 2, 2013, and incorporated by reference herein).
10.2*	Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan (filed as an exhibit to the Company's Schedule 14A on Definitive Proxy Statement for 2014, as filed with the Securities and Exchange Commission on April 11, 2014, and incorporated by reference herein).

Exhibit Number	Description
10.3	First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012 between Contango Oil & Gas Company and Exaro Energy III LLC (filed as Exhibit 10.1 to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012, and incorporated by reference herein).
10.4	Second Amended and Restated Limited Liability Company Agreement dated as of February 1, 2013 between Contango Oil & Gas Company and Exaro Energy III LLC (filed as Exhibit 10.4 to the Company's report on Form 10-K for the fiscal year ended December 31, 2018, as filed with the Securities and Exchange Commission on March 18, 2019, and incorporated by reference herein).
10.5	Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. (filed as Exhibit 10.56 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.6*	Contango Oil & Gas Company Director Compensation Plan (filed as Exhibit 10.4 to the Company's Report on Form 10-Q for the quarter ended March 31, 2017, as filed with the Securities and Exchange Commission on May 10, 2017, and incorporated by reference herein).
10.7*	Form of Contango Oil and Gas Company Stock Award Agreement (employees) (filed as Exhibit 10.7 to the Company's Report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).
10.8*	Form of Contango Oil and Gas Company Stock Award Agreement (executives) (filed as Exhibit 10.8 to the Company's Report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).
10.9	Rights Agreement, dated as of August 1, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018, and incorporated by reference herein).
10.10	Amendment to the Rights Agreement, dated as of November 21, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated November 21, 2018, as filed with the Securities and Exchange Commission on November 21, 2018, and incorporated by reference herein).
10.11	Credit Agreement, dated September 17, 2019, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of JPMorgan Chase Bank, N.A., Royal Bank of Canada and Cadence Bank, N.A. (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
10.12	Registration Rights Agreement, dated September 17, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
10.13	Registration Rights Agreement, dated November 1, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
10.14	First Amendment to Credit Agreement, dated November 1, 2019, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders Signatory hereto (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
10.15	Registration Rights Agreement, dated December 23, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated December 19, 2019, as filed with the Securities and Exchange Commission on December 23, 2019 and incorporated by reference herein).

Exhibit Number	Description
10.16	Second Amendment to Credit Agreement, dated June 9, 2020, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders Signatory hereto (filed as Exhibit 10.1 to the Company's Report on Form 8-K dated June 15, 2020, as filed with the Securities and Exchange Commission on June 15, 2020 and incorporated by reference herein).
10.17*	Amended and Restated 2009 Stock Incentive Plan (filed as Exhibit 10.2 to the Company's Report on Form 10-Q dated August 19, 2020, as filed with the Securities and Exchange Commission on August 19, 2020 and incorporated by reference herein).
10.18	Registration Rights Agreement, dated October 27, 2020, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated October 23, 2020, as filed with the Securities and Exchange Commission on October 28, 2020 and incorporated by reference herein).
10.19	Third Amendment to Credit Agreement, dated October 30, 2020, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders Signatory hereto (filed as Exhibit 10.1 to the Company's Report on Form 8-K dated October 30, 2020, as filed with the Securities and Exchange Commission on November 5, 2020 and incorporated by reference herein).
10.20	Registration Rights Agreement, dated December 1, 2020, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated November 29, 2020, as filed with the Securities and Exchange Commission on December 3, 2020 and incorporated by reference herein).
10.21*	Contango Oil & Gas Company Director Compensation Plan. †
10.22	Fourth Amendment to Credit Agreement, dated January 21, 2021, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders Signatory hereto. †
21.1	List of Subsidiaries. †
21.2	Organizational Chart. †
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of W.D. Von Gonten & Co. †
23.3	Consent of Grant Thornton LLP. †
24.1	Powers of Attorney (included on signature page). †
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. ††
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. ††
99.1	Report of William M. Cobb & Associates, Inc. †
99.2	Report of W.D. Von Gonten and Company. †
101	Interactive Data Files. †

* Indicates a management contract or compensatory plan or arrangement

† Filed herewith

†† Furnished herewith

Item 16. ***Form 10-K Summary***

None.

SIGNATURES

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

CONTANGO OIL & GAS COMPANY

By: /s/ WILKIE S. COLYER Date: March 10, 2021
Wilkie S. Colyer
Chief Executive Officer

POWER OF ATTORNEY

Know all men by these presents, that the undersigned constitutes and appoints Wilkie S. Colyer and E. Joseph Grady as his true and lawful attorneys-in-fact and agent, with full power of substitution for him and in his name, place and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ WILKIE S. COLYER Wilkie S. Colyer	Chief Executive Officer (principal executive officer) and Director	March 10, 2021
/s/ E. JOSEPH GRADY E. Joseph Grady	Chief Financial Officer (principal financial officer) and Chief Accounting Officer (principal accounting officer)	March 10, 2021
/s/ JOHN C. GOFF John C. Goff	Director	March 10, 2021
/s/ JOSEPH J. ROMANO Joseph J. Romano	Director	March 10, 2021
/s/ B. A. BERILGEN B. A. Berilgen	Director	March 10, 2021
/s/ ELLIS L. MCCAIN Ellis L. McCain	Director	March 10, 2021

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Texas corporation) and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of operations, cash flows, and shareholders' equity for each of the two years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the 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 two years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

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

Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves

As described further in Notes 2 and 5 to the financial statements, the Company accounts for its oil and gas properties using the successful efforts method of accounting which requires management to estimate reserve volumes and future net revenues to record depletion expense and to assess if there are indications the carrying value of certain properties exceed the fair value and if so, determine the fair value of its oil and gas properties to measure impairment. To estimate the volume of reserves and future net revenues, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties, and forecasting the timing and volume of production associated with the Company's development plan for undeveloped properties. In addition, the estimation of reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with reserves to determine if wells are expected, with reasonable certainty, to be economical under the pricing assumptions required in the estimation of depletion expense and impairment evaluation and measurements. We identified the estimation of proved reserves of oil and gas properties, due to its impact on depletion expense and the evaluation and measurement of impairment, as a critical audit matter.

The principal consideration for our determination that the estimation of reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions, which require a high degree of subjectivity necessary to estimate the volume and future revenues of the Company’s reserves, could have a significant impact on the measurement of depletion or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We evaluated the level of knowledge, skill and ability of the Company’s reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company’s proved reserves, and read the reserve reports prepared by the Company’s reservoir engineering specialists.

- We tested the accuracy of the Company’s depletion calculations and impairment evaluation and measurement that included these proved reserve reports.

- We evaluated sensitive inputs and assumptions used to determine reserve volumes and other cash flow inputs and assumptions derived from the Company’s accounting records. These assumptions included historical pricing differentials, current and future operating costs, estimated future capital costs, and ownership interests. We tested management’s process for determining the assumptions, including examining the underlying support on a sample basis for reasonableness and accuracy. Specifically, our audit procedures involved testing management’s assumptions as follows:

    - Compared the estimated pricing differentials used in the reserve reports to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
    - Evaluated models used to estimate the future operating costs in the reserve reports and compared amounts to historical operating costs;
    - Evaluated the method used to determine the future capital costs and compared estimated future capital costs used in the reserve reports to amounts expended for recently drilled and completed wells;
    - Tested the ownership interests used in the reserve reports by inspecting land and title records;
    - Evaluated the Company’s evidence supporting the amount of proved undeveloped properties reflected in the reserve reports by examining historical conversion rates and support for the Company’s ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the forecasted production in the reserve reports by comparing to historical actual results and to the prior year or preceding period reserve reports.

/s/ GRANT THORNTON LLP
We have served as the Company’s auditor since 2002.

Houston, Texas
March 10, 2021

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except shares)

	December 31, 2020	December 31, 2019
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,383	$ 1,624
Accounts receivable, net	37,862	39,567
Prepaid expenses	3,360	1,191
Current derivative asset	2,996	3,819
Inventory	442	186
Deposits and other	763	—
Total current assets	46,806	46,387
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, successful efforts method of accounting:		
Proved properties	1,274,508	1,306,916
Unproved properties	16,201	27,619
Other property and equipment	1,669	1,655
Accumulated depreciation, depletion, amortization and impairment	(1,190,475)	(1,045,070)
Total property, plant and equipment, net	101,903	291,120
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	6,793	6,766
Long-term derivative asset	497	357
Right-of-use lease assets	5,448	5,885
Debt issuance costs	1,782	3,311
Deposits	7,038	—
Total other non-current assets	21,558	16,319
TOTAL ASSETS	$ 170,267	$ 353,826
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 83,970	$ 104,593
Current derivative liability	1,317	3,951
Current asset retirement obligations	4,249	2,003
Total current liabilities	89,536	110,547
NON-CURRENT LIABILITIES:		
Long-term debt	12,369	72,768
Long-term derivative liability	1,648	2,020
Asset retirement obligations	48,523	49,662
Lease liabilities	2,624	2,789
Total non-current liabilities	65,164	127,239
Total liabilities	154,700	237,786
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
SHAREHOLDERS' EQUITY:		
Series C convertible preferred stock, $0.04 par value, no shares authorized, issued and outstanding at December 31, 2020 and 2,700,000 shares authorized, issued and outstanding at December 31, 2019	—	108
Common stock, $0.04 par value, 400 million shares authorized, 173,830,390 shares issued and 173,737,816 shares outstanding at December 31, 2020, 128,985,146 shares issued and 128,977,816 shares outstanding at December 31, 2019	6,941	5,148
Additional paid-in capital	535,192	471,778
Treasury shares at cost (92,574 shares at December 31, 2020 and 7,330 shares at December 31, 2019)	(248)	(18)
Accumulated deficit	(526,318)	(360,976)
Total shareholders' equity	15,567	116,040
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 170,267	$ 353,826

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,	
	2020	**2019**
REVENUES:		
Oil and condensate sales	$ 62,461	$ 44,705
Natural gas sales	31,381	22,380
Natural gas liquids sales	17,078	9,427
Fee for service revenues	2,000	—
Total revenues	112,920	76,512
EXPENSES:		
Operating expenses	72,847	33,205
Exploration expenses	11,594	1,003
Depreciation, depletion and amortization	30,032	39,807
Impairment & abandonment of oil and natural gas properties	168,802	128,290
General and administrative expenses	24,940	24,938
Total expenses	308,215	227,243
OTHER INCOME (EXPENSE):		
Gain (loss) from investment in affiliates (net of income taxes)	27	742
Gain from sale of assets	4,501	518
Interest expense	(5,022)	(8,596)
Gain (loss) on derivatives, net	27,585	(3,357)
Other income	3,609	1,848
Total other income	30,700	(8,845)
NET LOSS BEFORE INCOME TAXES	(164,595)	(159,576)
Income tax provision	(747)	(220)
NET LOSS ATTRIBUTABLE TO COMMON STOCK	$ (165,342)	$ (159,796)
NET LOSS PER SHARE:		
Basic	$ (1.20)	$ (2.95)
Diluted	$ (1.20)	$ (2.95)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
Basic	137,522	54,136
Diluted	137,522	54,136

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2020	Year Ended December 31, 2019
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (165,342)	$ (159,796)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	30,032	39,807
Impairment of oil and natural gas properties	168,732	126,964
Exploration expenditures - dry hole costs	10,455	—
Amortization of debt issuance costs	1,603	144
Deferred income taxes	—	424
Gain on sale of assets	(4,501)	(518)
Gain from investment in affiliates	(27)	(742)
Stock-based compensation	4,270	2,352
Unrealized loss (gain) on derivative instruments	(2,321)	5,973
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable & other	1,463	(9,903)
Decrease (increase) in prepaid expenses	(2,169)	451
Increase in inventory	(256)	—
Increase (decrease) in accounts payable & advances from joint owners	(6,279)	10,739
Increase (decrease) in other accrued liabilities	(7,477)	13,019
Decrease (increase) in income taxes receivable, net	281	(85)
Increase (decrease) in income taxes payable, net	233	(153)
Deposits and other	(7,801)	(6,966)
Net cash provided by operating activities	$ 20,896	$ 21,710
CASH FLOWS FROM INVESTING ACTIVITIES:		
Oil & natural gas exploration & development expenditures	$ (21,689)	$ (42,737)
Acquisition of oil & natural gas properties	—	(112,075)
Additions to furniture & equipment	(13)	(53)
Sale of oil and natural gas properties	349	10
Net cash used in investing activities	$ (21,353)	$ (154,855)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under Credit Agreement	$ 79,700	$ 256,923
Repayments under Credit Agreement	(143,468)	(244,154)
Payroll Protection Program Loan	3,369	—
Net proceeds from equity offerings	60,919	125,710
Purchase of treasury stock	(230)	(255)
Debt issuance costs	(74)	(3,455)
Net cash provided by financing activities	$ 216	$ 134,769
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ (241)	$ 1,624
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	1,624	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 1,383	$ 1,624

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
For the twelve months ended December 31, 2020
(in thousands, except share amounts)

	Preferred Stock		Common Stock		Additional Paid-in	Treasury	Accumulated	Total Shareholders'
	Shares	Amount	Shares	Amount	Capital	Stock	Deficit	Equity
Balance at December 31, 2019	2,700,000	$ 108	128,977,816	$ 5,148	$ 471,778	$ (18)	$ (360,976)	$ 116,040
Equity offering - common stock	—	—	—	—	(47)	—	—	(47)
Treasury shares at cost	—	—	(49,474)	—	—	(157)	—	(157)
Restricted shares activity	—	—	77,485	3	(3)	—	—	—
Stock-based compensation	—	—	—	—	350	—	—	350
Net loss	—	—	—	—	—	—	(105,255)	(105,255)
Balance at March 31, 2020	2,700,000	$ 108	129,005,827	$ 5,151	$ 472,078	$ (175)	$ (466,231)	$ 10,931
Equity offering - common stock	—	—	155,029	6	477	—	—	483
Conversion of preferred stock to common stock	(2,700,000)	(108)	2,700,000	108	—	—	—	—
Treasury shares at cost	—	—	(13,808)	—	—	(23)	—	(23)
Restricted shares activity	—	—	149,709	6	(6)	—	—	—
Stock-based compensation	—	—	—	—	265	—	—	265
Net loss	—	—	—	—	—	—	(28,034)	(28,034)
Balance at June 30, 2020	—	$ —	131,996,757	$ 5,271	$ 472,814	$ (198)	$ (494,265)	$ (16,378)
Equity offering - common stock	—	—	8,900	—	(27)	—	—	(27)
Treasury shares at cost	—	—	(3,678)	—	—	(8)	—	(8)
Restricted shares activity	—	—	1,011,699	41	(41)	—	—	—
Stock-based compensation	—	—	—	—	1,764	—	—	1,764
Net loss	—	—	—	—	—	—	(6,805)	(6,805)
Balance at September 30, 2020	—	$ —	133,013,678	$ 5,312	$ 474,510	$ (206)	$ (501,070)	$ (21,454)
Equity offering - common stock	—	—	40,645,891	1,626	58,883	—	—	60,509
Treasury shares at cost	—	—	(18,284)	—	—	(42)	—	(42)
Restricted shares activity	—	—	96,531	3	(3)	—	—	—
Stock-based compensation	—	—	—	—	1,802	—	—	1,802
Net loss	—	—	—	—	—	—	(25,248)	(25,248)
Balance at December 31, 2020	—	$ —	173,737,816	$ 6,941	$ 535,192	$ (248)	$ (526,318)	$ 15,567

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
For the twelve months ended December 31, 2019
(in thousands, except share amounts)

	Preferred Stock		Common Stock		Additional Paid-in Capital	Treasury Stock	Accumulated Deficit	Total Shareholders' Equity
	Shares	Amount	Shares	Amount				
Balance at December 31, 2018	—	$ —	34,158,492	$ 1,573	$ 339,981	$ (129,030)	$ (72,135)	$ 140,389
Equity offering - common stock	—	—	—	—	(86)	—	—	(86)
Treasury shares at cost	—	—	(49,415)	—	—	(186)	—	(186)
Restricted shares activity	—	—	307,650	12	(12)	—	—	—
Stock-based compensation	—	—	—	—	1,052	—	—	1,052
Net loss	—	—	—	—	—	—	(8,618)	(8,618)
Balance at March 31, 2019	—	$ —	34,416,727	$ 1,585	$ 340,935	$ (129,216)	$ (80,753)	$ 132,551
Equity offering - common stock	—	—	—	—	45	—	—	45
Treasury shares at cost	—	—	(16,133)	—	—	(50)	—	(50)
Restricted shares activity	—	—	42,249	2	(2)	—	—	—
Stock-based compensation	—	—	—	—	585	—	—	585
Net loss	—	—	—	—	—	—	(4,961)	(4,961)
Balance at June 30, 2019	—	$ —	34,442,843	$ 1,587	$ 341,563	$ (129,266)	$ (85,714)	$ 128,170
Equity offering - preferred stock	789,474	32	—	—	7,420	—	—	7,452
Equity offering - common stock	—	—	45,922,870	2,058	44,181	—	—	46,239
Treasury shares at cost	—	—	5,524,498	(221)	—	129,266	(129,045)	—
Treasury shares reissuance	—	—	(25,748)	(1)	1	—	—	—
Stock-based compensation	—	—	—	—	558	—	—	558
Net loss	—	—	—	—	—	—	(7,838)	(7,838)
Balance at September 30, 2019	789,474	$ 32	85,864,463	$ 3,423	$ 393,723	$ —	$ (222,597)	$ 174,581
Equity offering - preferred stock	3,802,838	152	—	—	26,154	—	—	26,306
Equity offering - common stock	—	—	19,000,000	760	44,942	—	—	45,702
Conversion of preferred stock to common stock	(1,892,312)	(76)	18,923,120	757	(629)	—	—	52
Treasury shares at cost	—	—	(7,330)	—	—	(18)	—	(18)
Restricted shares activity	—	—	(27,437)	(1)	1	—	—	—
Stock-based compensation	—	—	—	—	158	—	—	158
Will Energy and Juneau acquisitions	—	—	5,225,000	209	7,429	—	—	7,638
Net loss	—	—	—	—	—	—	(138,379)	(138,379)
Balance at December 31, 2019	2,700,000	$ 108	128,977,816	$ 5,148	$ 471,778	$ (18)	$ (360,976)	$ 116,040

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, "Contango" or the "Company") is a Fort Worth, Texas based independent oil and natural gas company. The Company's business is to maximize production and cash flow from its offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore properties primarily located in Oklahoma, Texas, Wyoming and Louisiana and use that cash flow to explore, develop and acquire oil and natural gas properties across the United States.

The following table lists the Company's primary producing areas as of December 31, 2020:

Location	Formation
Offshore Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Central Oklahoma	Mississippian, Woodford, Oswego, Cottage Grove, Chester, Cleveland and Red Fork
Western Anadarko	Tonkawa, Cottage Grove, Cleveland, Marmaton, Chase Sandstone, Morrow, Chester and Oswego
West Texas	Wolfcamp A and B
Other Onshore (TX, LA, WY)	Woodbine, Lewisville, Buda, Georgetown, Eagleford, and Muddy Sandstone

Impact of the COVID-19 Pandemic

A novel strain of the coronavirus ("COVID-19") surfaced in late 2019 and has spread, and continues to spread, around the world, including to the United States. In March 2020, the World Health Organization declared COVID-19 a pandemic, and the President of the United States declared the COVID-19 pandemic a national emergency. The COVID-19 pandemic has significantly affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the COVID-19 pandemic has resulted in travel restrictions, business closures and other restrictions that have disrupted the demand for oil throughout the world and, when combined with the oil supply increase attributable to the battle for market share among the Organization of Petroleum Exporting Countries ("OPEC"), Russia and other oil producing nations, resulted in oil prices declining significantly beginning in late February 2020. While there has been a modest recovery in oil prices, the length of this demand disruption is unknown, and there is significant uncertainty regarding the long-term impact to global oil demand, which negatively impacted the Company's results of operations and planned 2020 capital activities. Due to the extreme volatility in oil prices and the impact of COVID-19 on the financial condition of our upstream peers, the Company suspended its drilling program in the Southern Delaware Basin in the first quarter of 2020 and focused on certain measures that included, but were not limited to, the following:

- work from home initiatives for all but critical staff and the implementation of social distancing measures;
- a company-wide effort to cut costs throughout the Company's operations;
- utilization of the Company's available storage capacity to temporarily store a portion of its production for later sale at higher prices when advantageous to do so (such as the approximate 50,000 barrels of second quarter oil production we stored and sold during the third quarter of 2020 at higher oil prices);
- suspension of any further plans for operated onshore and offshore drilling in 2020;
- pursuit of additional "fee for service" opportunities similar to the Management Services Agreement entered into in June 2020 with Mid-Con Energy Partners, LP ("Mid-Con") (NASDAQ:MCEP), which was terminated at the closing of the Mid-Con Acquisition (as defined below) between the Company and Mid-Con on January 21, 2021); and
- potential acquisitions of PDP-heavy assets, with attractive, discounted valuations, in stressed/distressed scenarios or from non-industry owners, such as the Silvertip Acquisition (as defined below).

From the Company's initial entry into the Southern Delaware Basin in 2016 and through early 2019, the Company was focused on the development of its initial 6,500 net acre position in Pecos County, Texas ("Bullseye"), and in December 2018, the Company purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of its existing acreage ("NE Bullseye"). Contango's 2019 drilling program included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. In December 2019, the Company began completion operations on its fourth NE Bullseye well, which began producing in January 2020, and then suspended further drilling in the area in response to the dramatic decline in oil prices. As of December 31, 2020, the Company was producing from 18 wells over its approximate 16,200 gross operated (7,500 company net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations.

In September 2019, the Company entered into unrelated purchase agreements with Will Energy Corporation ("Will Energy") and White Star Petroleum, LLC and certain of its affiliates (collectively, "White Star") to purchase certain producing assets and undeveloped acreage, primarily in Oklahoma. These transactions closed during the three months ended December 31, 2019, (the "Will Energy Acquisition" and "White Star Acquisition") and were transformative, as production from these acquisitions represented approximately 70% of the Company's total net production for the year ended December 31, 2020. See Note 4 – "Acquisitions and Dispositions" for more information. In conjunction with the White Star Acquisition, the Company entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the "Credit Agreement"). In connection with the entry into the Credit Agreement, the Company repaid all obligations outstanding on, and terminated, its previous credit agreement with Royal Bank of Canada, which matured on October 1, 2019. The Credit Agreement has since been amended to increase the number of lenders from three to nine, and among other things, to adjust the borrowing base to $130.0 million on January 21, 2021 and $120.0 million on March 31, 2021. See Note 13 – "Long-Term Debt" for more information.

The Company completed two stock offerings in the third quarter of 2019. The Company completed an underwritten public offering (the "September 2019 Public Offering") of 51,447,368 shares of common stock (of which 5,524,498 were reissued treasury shares) for net proceeds of approximately $46.2 million, after deducting the underwriting discount and fees and expenses. Net proceeds from the September 2019 Public Offering were used to fund the cash portion of the purchase price for the Will Energy Acquisition and to repay borrowings outstanding under the Company's former revolving credit facility to provide incremental liquidity to support the Company's planned acquisition efforts. In conjunction with the September 2019 Public Offering, the Company also entered into a purchase agreement with affiliates of John C. Goff, a director and significant shareholder, and current chairman of the Company, to issue and sell in a private placement (the "Series A Private Placement") 789,474 shares of Series A contingent convertible preferred stock, which resulted in net proceeds of approximately $7.5 million.

The Company completed two additional stock offerings in the fourth quarter of 2019. In connection with the closing of the White Star Acquisition in November 2019, the Company completed a private placement of 1,102,838 shares of Series B contingent convertible preferred stock of the Company, which resulted in net proceeds of approximately $21.0 million (the "Series B Private Placement"). Net proceeds from the Series A Private Placement were used to fund a portion of the purchase price and related transaction expenses for the Will Energy Acquisition, and net proceeds from the Series B Private Placement were used to fund a portion of the purchase price and related transaction expenses for the White Star Acquisition. In December 2019, the Company also completed a private placement of 19,000,000 shares of common stock for net proceeds of approximately $45.7 million, after deducting the underwriting discount and fees and expenses (the "December 2019 Offering"). In conjunction with the December 2019 Offering, the Company also completed a private placement of 2,340,000 shares of Series C contingent convertible preferred stock (the "Series C Private Placement") with affiliates of Mr. Goff, Wilkie S. Colyer, Jr., the Company's chief executive officer, and others, which resulted in net proceeds of approximately $5.6 million. An additional 360,000 Series C contingent convertible preferred shares were issued in a private placement to the placement agents for the December 2019 Offering and Series C Private Placement, as partial consideration for their services in those offerings. Net proceeds from the December 2019 Offering and Series C Private Placement were used for general corporate purposes, including capital expenditures under the Company's Joint Development Agreement with Juneau Oil & Gas, LLC (discussed below).

In December 2019, the Company obtained approval from the holders of a majority of the voting power of the Company's capital stock to increase the number of common shares authorized for issuance from 100,000,000 to 200,000,000 common shares, at which time the Series A preferred shares automatically converted into 7,894,740 shares of common stock, the Series B preferred shares automatically converted into 11,028,380 shares of common stock, and the outstanding preferred shares were cancelled.

In December 2019, the Company entered into a Joint Development Agreement with Juneau Oil & Gas, LLC ("Juneau"), which provides the Company the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. The first such exploratory prospect acquired by the Company, located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline, was determined to be unsuccessful in June 2020. The Company is currently evaluating for future testing a number of exploratory prospects included in the Joint Development Agreement, including its Boss Hogg prospect located in the Eugene Island 298 Area in the shallow waters off of the

Louisiana coastline. The Company’s strategy and timing on the testing of the Boss Hogg will be determined during the year based on regulatory considerations, some of which are fluid at this time, and on operational considerations, including the availability of appropriate equipment.

Following the reduction in the Company’s drilling program in the latter half of 2019, which then led to the suspension of onshore drilling in the first quarter of 2020, the Company continued to identify opportunities for cost reductions and operating efficiencies in all areas of its operations, while also searching for new resource acquisition opportunities. Acquisition efforts have been, and will continue to be, focused on PDP-heavy assets where the Company might also be able to leverage its geological and operational experience and expertise to reduce operating expenses, enhance production and identify and develop additional drilling opportunities that the Company believes will enable it to economically grow production and add reserves.

On June 5, 2020, the Company announced the addition of a new corporate business line that includes offering a property management service (or a “fee for service”) for oil and natural gas companies with distressed or stranded assets, or companies with a desire to reduce administrative costs by engaging a contract operator of its oil and natural gas assets. As part of this service offering, the Company entered into a Management Services Agreement (“MSA”) with Mid-Con, effective July 1, 2020, to provide services as contract operator of record on Mid-Con’s oil and natural gas properties, along with certain administrative and management services, in exchange for an annual services fee of $4 million, paid ratably over the twelve month period, plus reimbursement of certain costs and expenses, a deferred fee of $166,666 per month for each month that the agreement is in effect (not to exceed $2 million), to be paid in a lump sum upon termination of the agreement, and warrants to purchase a minority equity ownership in Mid-Con. In connection with the Company’s acquisition of Mid-Con on January 21, 2021, the MSA was terminated, the deferred fee obligation was forgiven, and the warrants were cancelled. See Note 4 – “Acquisitions and Dispositions” for more information. The Company recorded $2.0 million in revenue during the year ended December 31, 2020 related to this MSA with Mid-Con, which is included in “Fee for services revenue” in the Company’s consolidated statements of operations.

On June 8, 2020, the stockholders of the Company, at the Company’s 2020 Annual Meeting of Stockholders, approved an amendment (the “Charter Amendment”) to its Amended and Restated Certificate of Formation with the Secretary of State of the State of Texas to increase the number of authorized shares of common stock, par value of $0.04 per share, of the Company from 200,000,000 shares to 400,000,000 shares, and also approved the conversion of the 2,700,000 shares of the Series C contingent convertible preferred stock, par value $0.04 per share, into 2,700,000 shares of the Company’s common stock. On June 10, 2020, the Company filed the Charter Amendment with the Secretary of State of the State of Texas.

On June 24, 2020, the Company entered into an Open Market Sale Agreement (the “Sale Agreement”) among the Company and Jefferies LLC (the “Sales Agent”). Pursuant to the terms of the Sale Agreement, the Company may sell, from time to time through the Sales Agent in the open market, subject to satisfaction of certain conditions, shares of the Company’s common stock, having an aggregate public offering price of up to $100,000,000 (the “Shares”) (the “ATM Program”). The Company intends to use the net proceeds from any sales through the ATM Program, after deducting the Sales Agent’s commission and the Company’s offering expenses, to repay borrowings under its Credit Agreement and for general corporate purposes, including, but not limited to, acquisitions and exploratory drilling. Under the ATM Program, the Company sold 163,929 shares during the year ended December 31, 2020 for net proceeds of $0.5 million.

On October 25, 2020, the Company and Mid-Con entered into an agreement and plan of merger providing for the acquisition by the Company of Mid-Con in an all-stock merger transaction in which Mid-Con would become a direct, wholly owned subsidiary of Contango (the “Mid-Con Acquisition”). On October 30, 2020, the Company entered into the Third Amendment (the “Third Amendment”) to its Credit Agreement under which, among other things, would increase the Company’s borrowing base from $75 million to $130.0 million, effective upon the closing of the Mid-Con Acquisition, with an automatic $10.0 million reduction in the borrowing base on March 31, 2021. The Mid-Con acquisition closed on January 21, 2021, with a total of 25,409,164 shares of Contango common stock issued. Upon closing of the Mid-Con Acquisition, the MSA was terminated, and the Company’s borrowing base was increased to $130.0 million. See Note 4 – “Acquisitions and Dispositions” and Note 13 – “Long-Term Debt” for further details.

Concurrently with the announcement of the Mid-Con Acquisition, the Company announced the execution of an agreement with a select group of institutional and accredited investors to sell 26,451,988 shares of common stock, which was completed on October 27, 2020. After deducting the underwriting discount and fees and expenses, the net proceeds were approximately $38.8 million, which were used for the Mid-Con Acquisition and for general corporate purposes, including the repayment of debt outstanding under the Company's Credit Agreement.

On November 27, 2020, the Company entered into a purchase and sale agreement (the "Purchase Agreement") with an undisclosed seller to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico (collectively the "Silvertip Acquisition") for aggregate consideration of approximately $58 million. In connection with the execution of the Purchase Agreement, the Company paid $7.0 million as a deposit for its obligations under the Purchase Agreement, which is included in the consolidated balance sheet as of December 31, 2020. The Silvertip Acquisition closed on February 1, 2021, for a net consideration of approximately $53.2 million (including the $7.0 million deposit previously paid), after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date. See Note 4 – "Acquisitions and Dispositions" for more information.

On December 1, 2020, the Company completed another private placement of 14,193,903 shares of common stock for net proceeds of approximately $21.7 million, after deducting the underwriting discount and fees and expenses. The net proceeds were used to fund the Silvertip Acquisition and for general corporate purposes, including the repayment of debt outstanding under the Company's Credit Agreement.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly-owned subsidiaries are consolidated.

Other Investments

The Company has two seats on the board of directors of Exaro and has significant influence, but not control, over the company. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method. Under the equity method, the Company's proportionate share of Exaro's net income increases the balance of its investment in Exaro, while a net loss or payment of dividends decreases its investment. In the consolidated statements of operations, the Company's proportionate share of Exaro's net income is reported as a single line-item in "Gain from investment in affiliates" (net of income taxes).

Use of Estimates

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

Revenue Recognition

Sales of oil, condensate, natural gas and natural gas liquids ("NGLs") are recognized at the time control of the products are transferred to the customer. Based upon the Company's past experience with its current purchasers and expertise in the market, collectability is probable, and there have not been payment issues with the Company's purchasers over the past year or currently. Generally, the Company's gas processing and purchase agreements indicate that the processors take control of the Company's gas at the inlet of the plant, and that control of residue gas is returned to the Company at the outlet of the plant. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs. The Company delivers oil and condensate to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product.

When sales volumes exceed the Company's entitled share, a production imbalance occurs. If production imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the

Company records a liability. Production imbalances have not had and currently do not have a material impact on the financial statements.

Generally, the Company’s contracts have an initial term of one year or longer but continue month to month unless written notification of termination in a specified time period is provided by either party to the contract. The Company receives purchaser statements from the majority of its customers, but there are a few contracts where the Company prepares the invoice. Payment is unconditional upon receipt of the statement or invoice.

The Company records revenue in the month production is delivered to the purchaser. Settlement statements may not be received for 30 to 90 days after the date production is delivered, and therefore the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences between the Company’s estimates and the actual amounts received for product sales are generally recorded in the following month that payment is received. Any differences between the Company’s revenue estimates and actual revenue received historically have not been significant. The Company has internal controls in place for its revenue estimation accrual process. The Company will continue to review all new or modified revenue contracts on a quarterly basis for proper treatment.

Cash Equivalents

Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of December 31, 2020, the Company had $1.4 million in cash and cash equivalents, after transferring cash balances at the end of each day to reduce outstanding debt under the Company’s revolving Credit Agreement to minimize debt service costs. Under the Company’s cash management system, checks issued but not yet presented to banks by the payee frequently result in book overdraft balances for accounting purposes and are classified in accounts payable in the consolidated balance sheets. At December 31, 2020, accounts payable included $2.9 million in outstanding checks that had not been presented for payment. At December 31, 2019, accounts payable included $6.1 million in outstanding checks that had not been presented for payment.

Accounts Receivable

The Company sells oil, natural gas and NGLs to a limited number of customers. In addition, the Company participates with other parties in the operation of oil and natural gas wells. Substantially all of the Company’s accounts receivables are due from either purchasers of oil, natural gas and NGLs or participants in oil and natural gas wells for which the Company serves as the operator. Generally, operators of oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells.

The allowance for doubtful accounts is an estimate of the losses in the Company’s accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.

Accounts receivable allowance for doubtful accounts was $2.3 million and $1.0 million as of December 31, 2020 and 2019, respectively. At December 31, 2020 and 2019, the carrying value of the Company’s accounts receivable approximated fair value.

Oil and Natural Gas Properties - Successful Efforts

The Company follows the successful efforts method of accounting for its oil and natural gas activities. The Company’s application of the successful efforts method of accounting for its oil and natural gas exploration and production activities requires judgment as to whether particular wells are developmental or exploratory, since lease acquisition costs and all developmental costs are capitalized, whereas exploratory drilling costs are continuously capitalized until the results are determined. If proved reserves are not discovered, the drilling costs are expensed as exploration costs. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred.

The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive oil or natural gas field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas, and therefore, management must estimate the portion of seismic costs to expense as exploratory. During the quarter ended June 30, 2020, the Company drilled an unsuccessful exploratory well in the Gulf of Mexico, resulting in a charge of $10.5 million for drilling and prospect costs included in “Exploration expenses” in the Company’s consolidated statements of operations for the year ended December 31, 2020.

The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management’s judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Depreciation, depletion and amortization ("DD&A") is calculated on a field basis using the unit of production method. Lease acquisition costs are amortized over remaining total proved reserves, and capitalized drilling and development costs of producing oil and natural gas properties, including related support equipment and facilities net of salvage value, are amortized over estimated proved developed oil and natural gas reserves. Upon sale or retirement of properties, the cost and related accumulated DD&A are eliminated from the accounts, and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least annually. Revisions are accounted for prospectively as changes in accounting estimates.

Other property and equipment are depreciated using the straight-line method over their estimated useful lives which range between three and 10 years.

Impairment of Oil and Natural Gas Properties

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field-by-field basis to the unamortized capitalized cost of the assets in that field. If the estimated future undiscounted cash flows, based on the Company’s estimate of future reserves, oil and natural gas prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and natural gas properties. Additionally, the Company may use appropriate market data to determine fair value.

In the first quarter of 2020, the COVID-19 pandemic and the resulting deterioration in the global demand for oil, combined with the failure by OPEC and Russia to reach an agreement on lower production quotas until April 2020, caused a dramatic increase in the supply of oil, a corresponding decrease in commodity prices, and reduced the demand for all commodity products. The remainder of 2020 was further adversely affected by the continuation of the COVID-19 pandemic and the actions and measures that countries, states, localities, central banks, international financing and funding organizations, stock markets, businesses and individuals have taken to address the spread of the coronavirus and associated illnesses, the continued volatility of the oil and gas market, and the failure of OPEC and Russia to consistently and fully adhere to the quotas delineated in their agreement. Consequently, during the three months ended March 31, 2020, the Company recorded a $143.3 million non-cash charge for proved property impairment of its onshore properties related to the dramatic decline in commodity prices, the “PV-10” (present value, discounted at a 10% rate) of its proved reserves, and the associated change in its current development plans for its proved undeveloped locations. In the fourth quarter of 2020, the Company recorded an additional $21.1 million non-cash charge for proved property impairment, of which $15.6 million related to its offshore properties as a result of performance revisions in reserves and the decline in gas prices and production yield. The total non-cash proved property impairment recorded during the year ended December 31, 2020 was $164.4 million.

For the year ended December 31, 2019, the Company recognized non-cash proved property impairment expense of $117.8 million due to reserve revisions which resulted from the negative impact of performance and price related revisions to the present value of the Company’s year-end proved reserves, and the relationship of that value to the historical carrying cost of its assets on the balance sheet. Included in the impairment charge was $34.5 million related to the Company’s proved offshore Gulf of Mexico properties, primarily a result of performance revisions associated with the re-evaluation of the projected field costs and recoverable condensate volumes. In addition, the Company recognized onshore proved property impairment expense of $83.3 million. The onshore impairment was due primarily to price and performance revisions, which led to the re-evaluation of the economics and future drilling plans for the proved undeveloped locations, which then resulted in the elimination of certain proved undeveloped locations due to the SEC's five-year development rule for such locations.

Unproved properties are reviewed quarterly to determine if there has been an impairment of the carrying value, with any such impairment charged to expense in the period. During the year ended December 31, 2020, the Company recorded a $4.3 million non-cash charge for unproved impairment expense related to undeveloped leases in its Central Oklahoma, Western Anadarko and Other Onshore regions. The Company recorded $2.6 million of this impairment expense in the first quarter of 2020, primarily related to leases the Company acquired from White Star and Will Energy in the fourth quarter of 2019, which were expiring in 2020, and the remaining $1.7 million of the impairment expense was recorded in the fourth quarter of 2020, due to leases expiring in 2021, all of which the Company has no plans to extend or develop as a result of the current commodity price environment and the Company's continued focus on cost saving and production enhancing strategic initiatives.

During the year ended December 31, 2019, the Company recognized impairment expense of approximately $9.2 million related primarily to lease expirations, and near-term expirations, in the Company's West Texas region.

Asset Retirement Obligations

Asset Retirement and Environmental Obligations ("ASC 410") requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records an asset retirement obligation ("ARO") to reflect the Company's legal obligation related to future plugging and abandonment of its oil and natural gas wells, platforms and associated pipelines and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis, the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells, platforms, and associated pipelines and equipment as these obligations are incurred. The liability is accreted to its present value each period, and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in DD&A expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate, changes in the remaining lives of the wells or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, the Company recognizes a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs. This gain or loss on abandonment is included in impairment and abandonment of oil and natural gas properties expense. See Note 12 – "Asset Retirement Obligation" for additional information.

Income Taxes

The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of December 31, 2020. As described in Note 16 – "Income Taxes" with respect to Section 382 Ownership Change, the amount of unrecognized tax benefits did not change materially from December 31, 2019. The amount of unrecognized tax benefits may change in the next twelve months; however, the Company does not expect the change to have a significant impact on its financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its consolidated statements of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company's federal and state tax returns for 2009 – 2020 remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from oil and natural gas sales or joint interest billings to a limited number of third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. See Note 3 – "Concentration of Credit Risk" for additional information.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt. On September 17, 2019, the Company entered into the new revolving Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders and incurred $1.8 million of arrangement and upfront fees in connection with the Credit Agreement. On November 1, 2019, the Credit Agreement was amended to add two additional lenders and increase the borrowing base thereunder, and the Company incurred an additional $1.6 million of debt issuance costs. On June 9, 2020, the Credit Agreement was amended to, among other things, reduce the borrowing base. No fees were incurred for the Second Amendment; however, during the three months ended June 30, 2020, the Company expensed $1.0 million of the debt issuance costs discussed above which originally were to be amortized over the life of the loan, due to the reduction in the borrowing base per the Second Amendment. On October 30, 2020, the Company entered into the Third Amendment to the Credit Agreement under which, among other things, increased the Company's borrowing base from $75.0 million to $130.0 million, effective upon the closing of the Mid-Con Acquisition on January 21, 2021. The Company initially incurred $0.1 million in fees related to the Third Amendment during the three months ended December 31, 2020. During the year ended December 31, 2020, the Company amortized debt issuance costs of $1.6 million related to its Credit Agreement, including the $1.0 million mentioned above. As of December 31, 2020, the remaining balance of these debt issuance costs was $1.8 million, which will be amortized through September 17, 2024, with amortization expense included in the interest expense line item in the Company's consolidated statements of operations.

In January 2021, the Company incurred an additional $0.9 million in fees related to the Third Amendment becoming effective on January 21, 2021, in connection with the closing of the Mid-Con Acquisition. These fees will also be amortized over the remaining term of the loan.

Stock-Based Compensation

The Company applies the fair value based method to account for stock based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the requisite service period, which generally aligns with the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each restricted stock award is estimated as of the date of grant. The fair value of the performance stock units is estimated as of the date of grant using the Monte Carlo simulation pricing model.

Inventory

Inventory consists primarily of casing and tubing stored temporarily, which will be used for drilling or completion of wells. Inventory is recorded at the lower of cost or market using specific identification method.

Derivative Instruments and Hedging Activities

The Company accounts for its derivative activities under the provisions of ASC 815, Derivatives and Hedging ("ASC 815"). ASC 815 establishes accounting and reporting requirements that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, the Company hedges a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction using variable to fixed swaps and collars. The Company elected to not designate any of its derivative positions for hedge accounting. Accordingly, the net change in the mark-to-market valuation of these positions as well as all payments and receipts on settled derivative contracts are recognized in "Gain (loss) on derivatives, net" on the consolidated statements of operations for the years ended December 31, 2020 and 2019. Derivative instruments with settlement dates within one year are included in current assets or liabilities, whereas derivative instruments with settlement dates exceeding one year are included in non-current assets or liabilities. The Company calculates the asset or liability for current and non-current derivative instruments for each counterparty based on the settlement dates within the respective contracts. See Note 6 – "Derivative Instruments" for additional information.

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the "Parent Company"), filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Contango Resources, Inc., Contango Midstream Company, Contango Operators, Inc., Contaro Company, Contango Alta Investments, Inc. and any other of the Company's future subsidiaries specified in the prospectus supplement (each a "Subsidiary Guarantor") are Co-Registrants with the Parent Company under the registration statement, and the registration statement also registered guarantees of debt securities by the Subsidiary Guarantors. The Subsidiary Guarantors are wholly-owned by the Parent Company, either directly or indirectly, and any guarantee by the Subsidiary Guarantors will be full and unconditional. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. Finally, the Parent Company's wholly-owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Leases

The Company recognizes a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term on the Company's consolidated balance sheet. The Company does not include leases with an initial term of twelve months or less on the balance sheet. The Company recognizes payments on these leases within "Operating expenses" on its consolidated statements of operations. The Company accounts for lease and non-lease contract components as a lease. The Company has procedures to review any new or modified contracts which contain a physical asset on a quarterly basis and determine if an arrangement is, or contains, a lease and determines the proper treatment. See Note 9 – "Leases" for additional information.

Recent Accounting Pronouncements

In June 2016, the FASB issued ASU 2016-13 - Financial Instruments - Credit Losses ("Topic 326"): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including the Company's trade and joint interest billing receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date that is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model that increases the allowance when losses are probable. Initially, ASU 2016-13 was effective for all public companies for fiscal years beginning after December 15, 2019. The FASB subsequently issued ASU 2019-04 ("ASU 2019-04"): Codification Improvements to Topic 326, Financial Instruments - Credit Losses, Topic 815, Derivatives, and Topic 825, Financial Instruments and ASU 2019-05 ("ASU 2019-05"): Financial Instruments - Credit Losses (Topic 326) - Targeted Transition Relief. ASU 2019-04 and ASU 2019-05 provide certain codification improvements related to the implementation of ASU 2016-13 and targeted transition relief consisting of an option to irrevocably elect the fair value option for eligible instruments. In November 2019, the FASB issued ASU 2019-10 - Financial Instruments - Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates. This amendment deferred the effective date of ASU 2016-13 from January 1, 2020 to January 1, 2023 for calendar year-end smaller reporting companies, which includes the Company. The Company plans to defer the implementation of ASU 2016-13, and the related updates.

In November 2019, the FASB issued ASU 2019-12 - Income Taxes ("Topic 740"): Simplifying the Accounting for Income Taxes ("ASU 2019-12"). The amendments in ASU 2019-12 are part of an initiative to reduce complexity in accounting standards and simplify the accounting for income taxes by removing certain exceptions from Topic 740 and making minor improvements to the codification. The amendments in this update are effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The provisions of this update are not expected to have a material impact on the Company's financial position or results of operations.

In March 2020, the FASB issued ASU 2020-04 - Reference Rate Reform (“Topic 848”): Facilitation of the Effects of Reference Rate Reform on Financial Reporting (“ASU 2020-04”). ASU 2020-04 provides optional guidance, for a limited period of time, to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. The amendments in ASU 2020-04 provide optional expedients and exceptions for applying US GAAP to contracts, hedging relationships and other transactions affected by reference rate reform if certain criteria are met. The amendments in this ASU apply only to contracts, hedging relationships and other transactions that reference LIBOR, or another reference rate, expected to be discontinued because of reference rate reform. The Company is currently assessing the potential impact of ASU 2020-04 on its consolidated financial statements.

3. Concentration of Credit Risk

The customer base for the Company is concentrated in the oil and natural gas industry. The Company’s largest three purchasers contributed approximately 36% of the Company’s total production revenues for the year ended December 31, 2020. The Company’s sales to these purchasers are not secured with letters of credit, and in the event of non-payment, the Company could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on the Company’s financial position. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

4. Acquisitions and Dispositions

Mid-Con Acquisition

On October 25, 2020, the Company entered into an Agreement and Plan of Merger (the “Merger Agreement’) with Mid-Con and Mid-Con Energy GP, LLC, the general partner of Mid-Con (“Mid-Con GP”), pursuant to which Mid-Con will merge with and into Michael Merger Sub LLC, a Delaware limited liability company and a wholly-owned, direct subsidiary of the Company. The Mid-Con Acquisition, which closed on January 21, 2021, was unanimously approved by the conflicts committee of the board of directors of Mid-Con, by the full board of directors of Mid-Con, by the disinterested directors of the board of directors of the Company and was subject to shareholder and unitholder approvals and other customary conditions to closing. At the effective time of the Mid-Con Acquisition (the “Effective Time”), each common unit representing limited partner interests in Mid-Con issued and outstanding immediately prior to the Effective Time (other than treasury units or units held by Mid-Con GP) was converted automatically into the right to receive 1.75 shares of the Company’s common stock. A total of 25,409,164 shares of Contango common stock were issued at the closing of the Mid-Con Acquisition. As of January 21, 2021, John C. Goff, Chairman of the Board of Directors of the Company, beneficially owned approximately 56.4% of the common units of Mid-Con, and Travis Goff, John C. Goff’s son and the President of Goff Capital, Inc., served on the board of directors of the general partner of Mid-Con. The Company’s senior management team will run the combined company, and Contango’s board of directors will remain intact as the board of directors of the combined company. The combined company is headquartered in Fort Worth, Texas.

The Mid-Con acquisition will be accounted for as a business combination. Therefore, the purchase price will be allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by the Company in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for the timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. The Company expects to complete the purchase price allocation during the twelve-month period following the acquisition date. The following table sets forth the Company’s preliminary allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

		Purchase Price Allocation (in thousands)
Consideration:		
Cash	$	14,520
Exchange ratio of Contango shares for Mid-Con common units		1.75
Contango common stock to be issued to Mid-Con unitholders		25,409
Issue price		3.13
Total consideration	$	79,530
Liabilities Assumed:		
Accounts payable	$	5,596
Other current liabilities		457
Revolving credit facility		68,487
Asset retirement obligations		29,241
Total liabilities assumed	$	103,781
Assets acquired:		
Cash and cash equivalents	$	776
Accounts receivable		4,398
Current derivative asset		3,141
Prepaid expenses		162
Proved oil and natural gas properties		172,607
Other property and equipment		730
Other non-current assets		1,497
Total assets acquired	$	183,311

The following unaudited pro forma combined condensed financial data for the years ended December 31, 2020 was derived from the historical financial statements of the Company after giving effect to the Mid-Con acquisition, as if it had occurred on January 1, 2020. The below information reflects pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including the depletion of the fair-valued proved oil and natural gas properties acquired from Mid-Con. 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 the Company to integrate the assets acquired. The pro forma consolidated statement of operations data has been included for comparative purposes only, is not necessarily indicative of the results that might have occurred had the acquisition taken place on January 1, 2020 and is not intended to be a projection of future results.

(In thousands except for per share amounts)		Year Ended December 31, 2020
Revenues	$	150,569
Net loss	$	(188,178)
Basic Earnings per share	$	(1.02)
Diluted earnings per share	$	(1.02)

Silvertip Acquisition

On November 27, 2020, the Company entered into the Purchase Agreement with an undisclosed seller to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico, for aggregate consideration of approximately $58 million in cash. In connection with the execution of the Purchase Agreement, the Company paid $7.0 million as a deposit for its obligations under the Purchase Agreement, which is included in the consolidated balance sheet as of December 31, 2020. The Silvertip Acquisition closed on February 1, 2021, and a balance of $46.2 million was paid upon closing, after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date.

Juneau Joint Development Agreement

On December 23, 2019, the Company entered into a Joint Development Agreement with Juneau for aggregate consideration of $6.0 million, consisting of $1.69 million in cash and 1,725,000 shares of common stock of the Company. This agreement provides the Company the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. The first such exploratory prospect acquired by the Company was the Iron Flea prospect located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline, which was determined to be unsuccessful in June 2020. The Company is currently evaluating for future testing a number of exploratory prospects included in the Joint Development agreement, including the Boss Hogg prospect, located in the Eugene Island 298 Area in the shallow waters off of the Louisiana coastline. Management considers this Boss Hogg prospect to be an excellent complement to its PDP-oriented acquisition strategy and believes it could provide a very compelling economic value proposition, even in the current low oil price environment. The Company is currently working through regulatory considerations and operational factors, including the availability of appropriate equipment, in determining the ultimate strategy for, and timing on, the testing of that prospect.

White Star Acquisition

On September 30, 2019, the Company entered into an asset purchase and sale agreement with White Star to acquire certain assets and liabilities, including approximately 306,000 net acres located in the STACK, Anadarko and Cherokee operating districts in Oklahoma. The closing of the White Star Acquisition occurred on November 1, 2019, for a total aggregate consideration of $132.5 million. Following adjustments for the results of operations for the period between the effective and closing dates, and other estimated, customary closing adjustments, the net consideration paid was approximately $95.7 million in cash.

The White Star Acquisition was accounted for as a business combination. Therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and natural gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and natural gas reserves, expectations for the timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. The following table sets forth the Company's allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

		Purchase Price Allocation (in thousands)
Consideration:		
Cash	$	95,722
Total consideration	$	95,722
Liabilities Assumed:		
Accounts payable	$	6,618
Revenue and royalties payable		11,165
Suspended revenue and royalties		22,011
Lease liabilities		3,614
Total liabilities assumed	$	43,408
Assets acquired:		
Accounts receivable	$	18,037
Other current assets		1,413
Proved oil and natural gas properties		113,150
Unevaluated properties		2,611
Right-of-use lease assets		3,614
Other assets		305
Total assets acquired	$	139,130

The purchase price allocated to the assets acquired increased to $139.1 million from the previously reported $138.5 million due to an increase in the value of inventory acquired of $1.0 million and a decrease in the value of unevaluated properties acquired of $0.4 million. Approximately $21.4 million of revenues and $16.3 million of direct operating expenses attributed to the White Star Acquisition are included in the Company's consolidated statements of operations for the period of the closing date on November 1, 2019 through December 31, 2019.

The following unaudited pro forma combined condensed financial data for the year ended December 31, 2019 was derived from the historical financial statements of the Company after giving effect to the White Star Acquisition, as if it had occurred on January 1, 2018. The below information reflects pro forma adjustments for the private placement of the Company's Series B contingent convertible preferred stock and an increase in borrowings under the Company's Credit Agreement, the proceeds of which were used to pay the purchase price of the White Star Acquisition, as well as pro forma adjustments based on then currently available information and certain assumptions that the Company believed were reasonable, including the depletion of the fair-valued proved oil and natural gas properties acquired from White Star and the exclusion of acquisition-related costs incurred by the Company of approximately $1.9 million for the year ended December 31, 2019. The pro forma results of operations do not include any cost savings or other synergies that may have resulted from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the assets acquired. In addition, the results of operations include non-cash impairment expense for White Star based on historical costs and not the fair value of the oil and natural gas properties acquired as reflected in the allocation of the purchase price. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the periods presented, as they were not deemed material. The pro forma consolidated statements of operations data has been included for comparative purposes only, is not necessarily indicative of the results that might have occurred had the acquisition taken place on January 1, 2018 and is not intended to be a projection of future results.

(In thousands except for per share amounts)		**Year Ended December 31, 2019**
Revenues	$	207,530
Net loss	$	(265,760)
Basic Earnings per share	$	(4.20)
Diluted earnings per share	$	(4.20)

Will Energy Acquisition

On September 12, 2019, the Company announced it entered into a contribution and purchase agreement with Will Energy to acquire approximately 155,900 net acres located in North Louisiana (8,000 net acres) and the Western Anadarko Basin in Western Oklahoma and the Texas Panhandle (147,900 net acres). Closing of the Will Energy Acquisition occurred on October 25, 2019, for a total aggregate consideration of $23 million. Following adjustments for sales of non-core, non-operated Louisiana properties by Will Energy prior to closing, the results of operations for the period between the effective and closing dates, and other estimated, customary closing adjustments, the net consideration paid consisted of $14.0 million in cash and 3.5 million shares of common stock.

Non-Core Assets Sales

During the years ended December 31, 2020 and 2019, the Company completed certain non-core asset sales to enhance its liquidity, eliminate marginal assets and reduce administrative costs. These asset sales provide some immediate liquidity and improve the Company's balance sheet by removing future asset retirement obligations.

On June 1, 2020, the Company closed on the sale of certain producing and non-producing properties located in its Central Oklahoma and Western Anadarko regions. These non-core, marginally economic properties were a minor portion of the value of properties acquired from Will Energy and were sold in exchange for the buyer's assumption of the plugging and abandonment liabilities of these properties and revenue held in suspense. The Company recorded a gain of $4.2 million as a result of the buyer's assumption of the asset retirement obligations associated with the sold properties.

On April 1, 2020, the Company closed on the sale of certain non-producing properties located in its Central Oklahoma region. These properties were a minor portion of the value of properties acquired from White Star and were sold for approximately $0.5 million. The Company recorded a gain of $0.2 million as a result of the buyer's assumption of the asset retirement obligations associated with the sold properties.

On July 1, 2019, the Company sold certain minor, non-core operated assets located in Frio and Zavala counties, Texas in exchange for the buyer's assumption of the plugging and abandonment liabilities of the properties. The Company recorded a gain of $0.2 million after removal of the asset retirement obligations associated with the sold properties.

On June 10, 2019, the Company sold certain minor, non-core operated assets located in Lavaca and Wharton counties, Texas in exchange for the buyer's assumption of the plugging and abandonment liabilities of the properties. The Company recorded a gain of $0.4 million related to the buyer's assumption of the asset retirement obligations associated with the sold properties.

5. Fair Value Measurements

Pursuant to ASC 820, Fair Value Measurements and Disclosures ("ASC 820"), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as 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 (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Derivatives are recorded at fair value at the end of each reporting period. The Company records the net change in the fair value of these positions in "Gain (loss) on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 6 – "Derivative Instruments" for additional discussion of derivatives.

During the year ended December 31, 2020, the Company's derivative contracts were with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. As such, the Company was exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company did not anticipate any nonperformance. The Company did not post collateral under any of these contracts as they are secured under the Credit Agreement or under unsecured lines of credit with non-bank counterparties.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Credit Agreement approximates carrying value because the interest rate approximates current market rates and are re-set at least every three months. See Note 13 – "Long-Term Debt" for further information.

Fair value estimates used for non-financial assets are evaluated at fair value on a non-recurring basis and include oil and natural gas properties evaluated for impairment when facts and circumstances indicate that there may be an impairment. If the unamortized cost of properties exceeds the undiscounted cash flows related to the properties, the value of the properties is compared to the fair value estimated as discounted cash flows related to the risk-adjusted proved, probable and possible reserves related to the properties. Fair value measurements based on these inputs are classified as Level 3.

Impairments

Contango tests proved oil and natural gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and natural gas properties on a field-by-field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and natural gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period.

Asset Retirement Obligations

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3 at inception.

6. Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company typically hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. The Company believes that these derivative arrangements, although not free of risk, allow it to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of oil, natural gas and natural gas liquids sales. Moreover, because its derivative arrangements apply only to a portion of its production, the Company's strategy provides only partial protection against declines in commodity prices. Such arrangements may expose the Company to risk of financial loss in certain circumstances. The Company continuously reevaluates its hedging programs in light of changes in production, market conditions and commodity price forecasts.

As of December 31, 2020, the Company's oil and natural gas derivative positions consisted of "swaps". Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for oil and natural gas. The Company has also, from time to time, entered into "costless collars" derivative positions. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put, which establishes a minimum price.

It is the Company's practice to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The Company did not post collateral under any of these contracts as they are secured under the Credit Agreement or under unsecured lines of credit with non-bank counterparties.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in “Gain (loss) on derivatives, net” on the consolidated statements of operations. See Note 5 – “Fair Value Measurements” for additional information.

The Company currently has derivative contracts in place to cover production periods through the first quarter of 2023, which include the hedges novated from Mid-Con and the additional hedges entered into in the first quarter of 2021, as discussed below. These contracts include oil hedges for 2.1 MMBbls of 2021 production with an average floor price of $54.85 per barrel and 1.4 MMBbls of 2022 production with an average floor price of $50.24 per barrel. For natural gas, the Company’s derivative contracts include 12.4 Bcf of 2021 production with an average floor price of $2.62 per MMBtu and 10.1 Bcf of 2022 production with an average floor price of $2.60 per MMBtu. Approximately 97% of the Company’s hedges are swaps, and the Company has no three-way collars or short puts.

The Company had the following financial derivative contracts in place as of December 31, 2020:

Commodity	Period	Derivative	Volume/Month		Price/Unit		Fair Value
Oil	Jan 2021 - March 2021	Swap	19,000	Bbls	$ 50.00	(1)	78
Oil	April 2021 - July 2021	Swap	12,000	Bbls	$ 50.00	(1)	71
Oil	Aug 2021 - Sept 2021	Swap	10,000	Bbls	$ 50.00	(1)	39
Oil	Jan 2021 - July 2021	Swap	62,000	Bbls	$ 52.00	(1)	1,490
Oil	Aug 2021 - Sept 2021	Swap	55,000	Bbls	$ 52.00	(1)	434
Oil	Oct 2021 - Dec 2021	Swap	64,000	Bbls	$ 52.00	(1)	840
Oil	April 2022 - Oct 2022	Swap	25,000	Bbls	$ 42.04	(1)	(784)
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$ 2.505	(2)	(1)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$ 2.505	(2)	(43)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$ 2.505	(2)	(4)
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$ 2.508	(2)	(3)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$ 2.508	(2)	(44)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$ 2.508	(2)	(4)
Natural Gas	Jan 2021 - March 2021	Swap	650,000	MMBtus	$ 2.508	(2)	(6)
Natural Gas	April 2021 - Oct 2021	Swap	400,000	MMBtus	$ 2.508	(2)	(400)
Natural Gas	Nov 2021 - Dec 2021	Swap	580,000	MMBtus	$ 2.508	(2)	(402)
Natural Gas	April 2021 - Nov 2021	Swap	70,000	MMBtus	$ 2.36	(2)	(175)
Natural Gas	Dec 2021	Swap	350,000	MMBtus	$ 2.36	(2)	(195)
Natural Gas	Jan 2022 - March 2022	Swap	780,000	MMBtus	$ 2.542	(2)	(865)
Natural Gas	April 2022 - July 2022	Swap	650,000	MMBtus	$ 2.515	(2)	252
Natural Gas	Aug 2022 - Oct 2022	Swap	350,000	MMBtus	$ 2.515	(2)	71
Natural Gas	Jan 2022 - March 2022	Swap	250,000	MMBtus	$ 3.149	(2)	179
	Total net fair value of derivative instruments (in thousands)						$ 528

(1) Based on West Texas Intermediate oil prices.

(2) Based on Henry Hub NYMEX natural gas prices.

The Company had the following financial derivative contracts in place as of December 31, 2019:

Commodity	Period	Derivative	Volume/Month		Price/Unit		Fair Value
Oil	Jan 2020 - June 2020	Swap	22,000	Bbls	$ 57.74	(1)	(289)
Oil	July 2020 - Dec 2020	Swap	15,000	Bbls	$ 57.74	(1)	68
Oil	Jan 2020 - March 2020	Swap	2,700	Bbls	$ 54.33	(1)	(51)
Oil	April 2020 - June 2020	Swap	2,500	Bbls	$ 54.33	(1)	(37)
Oil	July 2020	Swap	5,500	Bbls	$ 54.33	(1)	(21)
Oil	Aug 2020 - Oct 2020	Swap	2,500	Bbls	$ 54.33	(1)	(21)
Oil	Nov 2020 - Dec 2020	Swap	3,500	Bbls	$ 54.33	(1)	(12)
Oil	Jan 2020 - Feb 2020	Swap	42,500	Bbls	$ 54.70	(1)	(517)
Oil	March 2020 - July 2020	Swap	37,500	Bbls	$ 54.70	(1)	(842)
Oil	Aug 2020 - Dec 2020	Swap	35,000	Bbls	$ 54.70	(1)	(354)
Oil	Jan 2020 - Feb 2020	Swap	42,500	Bbls	$ 54.58	(1)	(527)
Oil	March 2020 - July 2020	Swap	37,500	Bbls	$ 54.58	(1)	(864)
Oil	Aug 2020 - Dec 2020	Swap	35,000	Bbls	$ 54.58	(1)	(373)
Oil	Jan 2020 - Oct 2020	Collar	3,442	Bbls	$ 52.00 - 65.70	(1)	18
Oil	Jan 2021 - March 2021	Swap	19,000	Bbls	$ 50.00	(1)	(291)
Oil	April 2021 - July 2021	Swap	12,000	Bbls	$ 50.00	(1)	(196)
Oil	Aug 2021 - Sept 2021	Swap	10,000	Bbls	$ 50.00	(1)	(67)
Oil	Jan 2021 - July 2021	Swap	62,000	Bbls	$ 52.00	(1)	(1,122)
Oil	Aug 2021 - Sept 2021	Swap	55,000	Bbls	$ 52.00	(1)	(157)
Oil	Oct 2021 - Dec 2021	Swap	64,000	Bbls	$ 52.00	(1)	(184)
Natural Gas	Jan 2020 - March 2020	Swap	425,000	MMBtus	$ 2.841	(2)	856
Natural Gas	Jan 2020 - March 2020	Collar	225,000	MMBtus	$ 2.45 - 3.40	(2)	209
Natural Gas	April 2020 - July 2020	Swap	400,000	MMBtus	$ 2.532	(2)	493
Natural Gas	Aug 2020 - Oct 2020	Swap	40,000	MMBtus	$ 2.532	(2)	25
Natural Gas	Nov 2020 - Dec 2020	Swap	375,000	MMBtus	$ 2.696	(2)	134
Natural Gas	Jan 2020 - March 2020	Swap	300,000	MMBtus	$ 2.53	(2)	325
Natural Gas	April 2020 - July 2020	Swap	400,000	MMBtus	$ 2.53	(2)	490
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000	MMBtus	$ 2.53	(2)	223
Natural Gas	Jan 2020 - March 2020	Swap	300,000	MMBtus	$ 2.532	(2)	327
Natural Gas	April 2020 - July 2020	Swap	400,000	MMBtus	$ 2.532	(2)	493
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000	MMBtus	$ 2.532	(2)	226
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$ 2.505	(2)	(78)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$ 2.505	(2)	99
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$ 2.505	(2)	4
Natural Gas	Jan 2021 - March 2021	Swap	185,000	MMBtus	$ 2.508	(2)	(75)
Natural Gas	April 2021 - July 2021	Swap	120,000	MMBtus	$ 2.508	(2)	104
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	MMBtus	$ 2.508	(2)	4
Natural Gas	Jan 2021 - March 2021	Swap	650,000	MMBtus	$ 2.508	(2)	(268)
Natural Gas	April 2021 - Oct 2021	Swap	400,000	MMBtus	$ 2.508	(2)	544
Natural Gas	Nov 2021 - Dec 2021	Swap	580,000	MMBtus	$ 2.508	(2)	20
			Total net fair value of derivative instruments (in thousands)				$ (1,684)

(1) Based on West Texas Intermediate oil prices.

(2) Based on Henry Hub NYMEX natural gas prices.

In addition to the above financial derivative instruments, the Company also had a costless swap agreement with a Midland WTI – Cushing oil differential swap price of $0.05 per barrel of oil. The agreement fixed the Company's exposure to that differential on 12,000 barrels of oil per month for January 2020 through June 2020 and 10,000 barrels per month for July 2020 through December 2020. The fair value of this costless swap agreement was in a liability position of $0.1 million as of December 31, 2019.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2020 (in thousands).

	Gross	Netting (1)	Total
Assets	$ 3,493	$ —	$ 3,493
Liabilities	$ (2,965)	$ —	$ (2,965)

(1) Represents counterparty netting under agreements governing such derivatives.

Derivatives listed above are recorded in "Current derivative asset or liability" and "Long-term derivative asset or liability" on the Company's consolidated balance sheet and include swaps that are carried at fair value.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2019 (in thousands).

	Gross	Netting (1)	Total
Assets	$ 4,176	$ —	$ 4,176
Liabilities	$ (5,971)	$ —	$ (5,971)

(1) Represents counterparty netting under agreements governing such derivatives.

Derivatives listed above are recorded in "Current derivative asset or liability" and "Long-term derivative asset or liability" on the Company's consolidated balance sheet and include swaps and costless collars that are carried at fair value.

The following table summarizes the effect of derivative contracts on the Consolidated Statements of Operations for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
Contract Type	**2020**	**2019**
Crude oil contracts	$ 18,561	$ 1,614
Natural gas contracts	6,703	1,002
Realized gain	$ 25,264	$ 2,616
Crude oil contracts	$ 8,120	$ (10,012)
Natural gas contracts	(5,799)	4,039
Unrealized gain (loss)	$ 2,321	$ (5,973)
Gain (loss) on derivatives, net	$ 27,585	$ (3,357)

In conjunction with the closing of the Mid-Con Acquisition in January 2021, the Company acquired the following additional derivative contracts via novation from Mid-Con:

Commodity	Period	Derivative	Volume/Month		Price/Unit	
Oil	Jan 2021	Swap	20,883	Bbls	$	55.78 [1]
Oil	Feb 2021	Swap	20,804	Bbls	$	55.78 [1]
Oil	March 2021	Swap	20,725	Bbls	$	55.78 [1]
Oil	April 2021	Swap	20,647	Bbls	$	55.78 [1]
Oil	May 2021	Swap	20,563	Bbls	$	55.78 [1]
Oil	June 2021	Swap	20,487	Bbls	$	55.78 [1]
Oil	July 2021	Swap	20,412	Bbls	$	55.78 [1]
Oil	Aug 2021	Swap	20,301	Bbls	$	55.78 [1]
Oil	Sept 2021	Swap	20,228	Bbls	$	55.78 [1]
Oil	Oct 2021	Swap	20,155	Bbls	$	55.78 [1]
Oil	Nov 2021	Swap	20,084	Bbls	$	55.78 [1]
Oil	Dec 2021	Swap	20,012	Bbls	$	55.78 [1]
Oil	Jan 2021	Collar	20,883	Bbls	$	52.00 - 58.80 [1]
Oil	Feb 2021	Collar	20,804	Bbls	$	52.00 - 58.80 [1]
Oil	March 2021	Collar	20,725	Bbls	$	52.00 - 58.80 [1]
Oil	April 2021	Collar	20,647	Bbls	$	52.00 - 58.80 [1]
Oil	May 2021	Collar	20,563	Bbls	$	52.00 - 58.80 [1]
Oil	June 2021	Collar	20,487	Bbls	$	52.00 - 58.80 [1]
Oil	July 2021	Collar	20,412	Bbls	$	52.00 - 58.80 [1]
Oil	Aug 2021	Collar	20,301	Bbls	$	52.00 - 58.80 [1]
Oil	Sept 2021	Collar	20,228	Bbls	$	52.00 - 58.80 [1]
Oil	Oct 2021	Collar	20,155	Bbls	$	52.00 - 58.80 [1]
Oil	Nov 2021	Collar	20,084	Bbls	$	52.00 - 58.80 [1]
Oil	Dec 2021	Collar	20,012	Bbls	$	52.00 - 58.80 [1]

(1) Based on West Texas Intermediate oil prices.

In the first quarter of 2021, the Company entered into the following additional derivative contracts:

Commodity	Period	Derivative	Volume/Month		Price/Unit		
Oil	March 2021 - Oct 2021	Swap	25,000	Bbls	$	54.77	(1)
Oil	Nov 2021 - Dec 2021	Swap	15,000	Bbls	$	54.77	(1)
Oil	March 2021	Swap	50,000	Bbls	$	63.31	(1)
Oil	April 2021	Swap	50,000	Bbls	$	63.13	(1)
Oil	May 2021	Swap	50,000	Bbls	$	62.71	(1)
Oil	June 2021	Swap	50,000	Bbls	$	62.17	(1)
Oil	July 2021	Swap	50,000	Bbls	$	61.50	(1)
Oil	Aug 2021	Swap	50,000	Bbls	$	60.94	(1)
Oil	Sep 2021	Swap	50,000	Bbls	$	60.38	(1)
Oil	Oct 2021	Swap	50,000	Bbls	$	59.89	(1)
Oil	Nov 2021	Swap	50,000	Bbls	$	59.46	(1)
Oil	Dec 2021	Swap	50,000	Bbls	$	59.01	(1)
Oil	Jan 2022	Swap	60,000	Bbls	$	52.94	(1)
Oil	Feb 2022	Swap	60,000	Bbls	$	52.65	(1)
Oil	March 2022	Swap	60,000	Bbls	$	52.29	(1)
Oil	April 2022	Swap	47,500	Bbls	$	51.98	(1)
Oil	May 2022	Swap	45,000	Bbls	$	51.71	(1)
Oil	June 2022	Swap	45,000	Bbls	$	51.41	(1)
Oil	July 2022	Swap	45,000	Bbls	$	51.13	(1)
Oil	Aug 2022	Swap	45,000	Bbls	$	50.89	(1)
Oil	Sep 2022	Swap	45,000	Bbls	$	50.65	(1)
Oil	Oct 2022	Swap	45,000	Bbls	$	50.45	(1)
Oil	Nov 2022	Swap	55,000	Bbls	$	50.26	(1)
Oil	Dec 2022	Swap	55,000	Bbls	$	50.22	(1)
Oil	Jan 2023	Swap	57,500	Bbls	$	49.81	(1)
Oil	Feb 2023	Swap	57,500	Bbls	$	49.63	(1)
Oil	Jan 2022	Swap	60,000	Bbls	$	52.96	(1)
Oil	Feb 2022	Swap	60,000	Bbls	$	52.66	(1)
Oil	March 2022	Swap	60,000	Bbls	$	52.27	(1)
Oil	April 2022	Swap	47,500	Bbls	$	51.96	(1)
Oil	May 2022	Swap	45,000	Bbls	$	51.72	(1)
Oil	June 2022	Swap	45,000	Bbls	$	51.42	(1)
Oil	July 2022	Swap	45,000	Bbls	$	51.13	(1)
Oil	Aug 2022	Swap	45,000	Bbls	$	50.90	(1)
Oil	Sep 2022	Swap	45,000	Bbls	$	50.66	(1)
Oil	Oct 2022	Swap	45,000	Bbls	$	50.47	(1)
Oil	Nov 2022	Swap	55,000	Bbls	$	50.26	(1)
Oil	Dec 2022	Swap	55,000	Bbls	$	50.01	(1)
Oil	Jan 2023	Swap	57,500	Bbls	$	49.79	(1)
Oil	Feb 2023	Swap	57,500	Bbls	$	49.62	(1)
Natural Gas	March 2021	Swap	100,000	MMBtus	$	2.96	(2)
Natural Gas	April 2021 - July 2021	Swap	350,000	MMBtus	$	2.96	(2)
Natural Gas	Aug 2021 - Oct 2021	Swap	500,000	MMBtus	$	2.96	(2)
Natural Gas	Nov 2021	Swap	450,000	MMBtus	$	2.96	(2)
Natural Gas	April 2022	Swap	175,000	MMBtus	$	2.51	(2)
Natural Gas	May 2022 - July 2022	Swap	150,000	MMBtus	$	2.51	(2)
Natural Gas	Aug 2022 - Oct 2022	Swap	400,000	MMBtus	$	2.51	(2)
Natural Gas	Nov 2022 - Feb 2023	Swap	750,000	MMBtus	$	2.72	(2)

(1) Based on West Texas Intermediate oil prices.

(2) Based on Henry Hub NYMEX natural gas prices.

7. Stock Based Compensation

Effective January 1, 2014, the Company implemented performance-based long-term bonus plans under its compensation plan at the time (the "2009 Plan") for the benefit of all employees through a Cash Incentive Bonus Plan ("CIBP") and a Long-Term Incentive Plan ("LTIP"). The specific targeted performance measures under these sub-plans are approved by the Compensation Committee and/or the Company's board of directors (the "Board"). Upon achieving the performance levels established each year, bonus awards under the CIBP and LTIP will be calculated as a percentage of base salary of each employee for the plan year. The CIBP and LTIP plan awards for each year are expected to be disbursed in the first quarter of the following year. Employees must be employed by the Company at the time that awards are disbursed to be eligible.

The CIBP awards will be paid in cash while LTIP awards will consist of restricted common stock, performance stock units and/or stock options. The number of shares of restricted common stock and the number of shares underlying the stock options granted will be determined based upon the fair market value of the common stock on the date of the grant.

Third Amended and Restated 2009 Incentive Compensation Plan

As of December 31, 2020, the Company had in place the Contango Oil & Gas Company Third Amended and Restated 2009 Incentive Compensation Plan ("the Third Amended 2009 Plan") which allows for stock options, restricted stock or performance stock units to be awarded to officers, directors and employees as a performance-based award.

On March 21, 2017, the Board amended and restated the Company's then existing incentive compensation plan through the adoption of the Second Amended 2009 Plan. The Second Amended 2009 Plan provides for both cash awards and equity awards to officers, directors, employees or consultants of the Company. On June 8, 2020 the Board amended and restated the Second Amended 2009 Plan through the adoption of the Third Amended 2009 Plan, which, among other things, increased the number of shares of the Company's common stock authorized for issuance pursuant to the Third Amended 2009 Plan by 9,000,000 shares and increased the maximum aggregate number of shares of common stock that may be granted to any individual during any calendar year from 250,000 to 1,000,000. Awards made under the Third Amended 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Under the terms of the Third Amended 2009 Plan, shares of the Company's common stock may be issued for plan awards. Stock options under the Third Amended 2009 Plan must have an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant officers and employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options granted generally expire after five or ten years. The vesting schedule for all equity awards varies from immediately to over a three-year period. As of December 31, 2020, the Company had approximately 6.2 million shares of equity awards available for future grant under the Third Amended 2009 Plan, assuming performance stock units are settled at 100% of target.

2005 Stock Incentive Plan

The 2005 Plan was adopted by the Company's Board in conjunction with the merger with Crimson Exploration, Inc. This plan expired on February 25, 2015, and therefore, no additional shares are available for grant.

Stock Options

A summary of stock options as of and for the years ended December 31, 2020 and 2019 is presented in the table below (dollars in thousands, except per share data):

	Year Ended December 31,			
	2020		2019	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of the period	20,964	$ 58.53	33,637	$ 55.82
Exercised	—	$ —	—	$ —
Expired / Forfeited	(1,117)	$ 39.00	(12,673)	$ 51.34
Outstanding, end of year	19,847	$ 59.62	20,964	$ 58.53
Aggregate intrinsic value	$ —		$ —	
Exercisable, end of year	19,847	$ 59.62	20,964	$ 58.53
Aggregate intrinsic value	$ —		$ —	
Available for grant, end of the period*	6,240,312		1,480,389	
Weighted average fair value of options granted during the period	$ —		$ —	

* Assumes performance stock units are settled at 100% of target.

During the years ended December 31, 2020 and 2019, the Company did not issue any stock options. During the years ended December 31, 2020 and December 31, 2019, 1,117 and 12,673 stock options previously issued were forfeited by former employees, respectively.

As of December 31, 2020, there were 19,847 stock options vested and exercisable under the 2005 Plan. The exercise price for such options ranges from $28.96 to $60.33 per share, with an average remaining contractual life of 0.2 years.

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the years ended December 31, 2020 and 2019, there was no excess tax benefit recognized. See Note 2 – “Summary of Significant Accounting Policies”.

Compensation expense related to employee stock option grants are recognized over the stock option’s vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model.

During the years ended December 31, 2020 and 2019, the Company did not recognize any stock option expense. The aggregate intrinsic value of stock options exercised/forfeited during each of the years ended December 31, 2020 and 2019 was zero.

Restricted Stock

During the year ended December 31, 2020, the Company issued 1,041,365 restricted stock awards to new and existing employees, which vest over three years, as part of their overall compensation package. During the year ended December 31, 2020, the Company issued 152,248 restricted stock awards to the members of the board of directors, which vest on the one-year anniversary of the date of grant, as well as an additional 50,914 restricted stock awards, in lieu of cash fees earned for the third quarter of 2020, which vested immediately. During the year ended December 31, 2020, 55,064 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $2.22, with a total grant date fair value of approximately $2.8 million with no adjustment for an estimated weighted average forfeiture rate.

During the year ended December 31, 2019, the Company issued 307,650 restricted stock awards to new and existing employees, which vest over three years, plus an additional 80,410 restricted stock awards to the members of the board of directors, which vest on the one-year anniversary of the date of grant, as part of their overall compensation package. During the year ended December 31, 2019, 91,346 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $2.91, with a total grant date fair value of approximately $1.1 million with no adjustment for an estimated weighted average forfeiture rate.

Restricted stock activity as of December 31, 2020 and 2019 and for the years then ended is presented in the table below (dollars in thousands, except per share data):

	2020			2019		
	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, beginning of the period	403,221	$ 3.66	$ 214	459,621	$ 7.26	$ 662
Granted	1,244,527	2.22	65	388,060	2.91	—
Vested	(289,636)	3.48	700	(353,114)	7.41	1,171
Canceled / Forfeited	(55,064)	2.45	16	(91,346)	4.08	41
Not vested, end of the period	1,303,048	2.38	228	403,221	3.66	214

The Company recognized approximately $1.3 million and $1.9 million in restricted stock compensation expense during the years ended December 31, 2020 and 2019, respectively, for restricted shares granted to its officers, employees and directors. The lower 2020 expense is primarily related to the issuance of stock in the third quarter of 2020 as compared to stock issued in the first quarter of 2019. As of December 31, 2020, there were 1,303,048 shares of unvested restricted stock outstanding, and an additional $2.3 million of compensation expense related to restricted stock remains to be recognized over the remaining vesting period of 2.1 years.

Performance Stock Units

Performance stock units (“PSUs”) represent the opportunity to receive shares of the Company’s common stock at the time of settlement. The number of shares to be awarded upon settlement of the PSUs may range from 0% to 300% of the targeted number of PSUs stated in the award agreements, contingent upon the achievement of certain share price appreciation targets compared to share appreciation of a specific peer group or peer group index over a three-year period. The PSUs vest at the end of the three-year performance period, with the final number of shares to be issued determined at that time, based on the Company’s share performance during the period compared to the average performance of the peer group.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model, which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the PSUs with shares of the Company’s common stock after three years, the PSU awards are accounted for as equity awards, and the fair value is calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

During the year ended December 31, 2020, the Company granted 2,846,140 PSUs to executive officers and certain employees as part of their overall compensation package. The performance period will be measured between May 1, 2020 and April 30, 2023. These granted PSUs were valued at a weighted average fair value of $4.90 per unit. All fair value prices were determined using the Monte Carlo simulation model. In January 2020, 77,485 shares of the PSUs granted in 2017 vested, of which 22,972 PSUs were withheld for taxes, and are included with the restricted stock activity in the consolidated statement of shareholders’ equity. In December 2020, 68,476 shares of the PSUs granted in 2018 vested, of which 18,284 PSUs were withheld for taxes and are included with the restricted stock activity in the consolidated statement of shareholders’ equity. No PSUs were forfeited during the year ended December 31, 2020. The Company recognized approximately $3.0 million in stock compensation expense related to PSUs during 2020. As of December 31, 2020, an additional $11.7 million of compensation expense related to PSUs remained to be recognized over the remaining vesting period of 2.3 years.

During the year ended December 31, 2019, the Company granted 117,105 PSUs to executive officers and employees as part of their overall compensation package, which will be measured between January 1, 2019 and December 31, 2021, and were valued at a weighted average fair value of $6.42 per unit. All fair value prices were determined using the Monte Carlo simulation model. During the year ended December 31, 2019, 71,945 PSUs were forfeited by former employees, including 49,773 PSU forfeitures due to the resignations of the Company’s former Senior Vice President of Exploration and Senior Vice President of Operations and Engineering in February 2019. The Company only recognized approximately $0.5 million in stock compensation expense related to PSUs during 2019, primarily due to the expiration of PSUs which failed to meet their target as of December 31, 2018 and the above referenced forfeitures.

8. Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market or through privately negotiated transactions. Purchases are made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market, and when the Company believes its stock price to be undervalued. Repurchased shares of common stock become authorized but unissued shares and may be issued in the future for general corporate and other purposes. No shares were purchased during the years ended December 31, 2020 and 2019. As of December 31, 2020, the Company had $31.8 million available under the share repurchase program for future purchases; however, repurchases could be limited by provisions of the Company's Credit Agreement.

9. Leases

As of January 1, 2019, the Company adopted Accounting Standards Codification Topic 842 – Leases ("ASC 842"), which requires lessees to recognize a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis, and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term on the Company's consolidated balance sheet.

During the year ended December 31, 2020, the Company entered into new compressor contracts with lease terms of twelve months or more, which qualify as operating leases. The Company also entered into new contracts for vehicles and office equipment with lease terms of twelve months or more, which qualify as finance leases. As of December 31, 2020, the Company's operating leases were for compressors and office space for two corporate offices and three field offices, while the Company's finance leases were for vehicles and office equipment. These leases do not have a material net impact on the Company's consolidated financial statements.

The following table summarizes the balance sheet information related to the Company's leases as of December 31, 2020 and December 31, 2019 (in thousands):

	December 31, 2020	December 31, 2019
Operating lease right of use asset (1)	$ 2,452	$ 4,316
Operating lease liability - current (2)	$ (1,832)	$ (2,597)
Operating lease liability - long-term (3)	(522)	(1,738)
Total operating lease liability	$ (2,354)	$ (4,335)
Financing lease right of use asset (1)	$ 2,996	$ 1,569
Financing lease liability - current (2)	$ (940)	$ (524)
Financing lease liability - long-term (3)	(2,102)	(1,051)
Total financing lease liability	$ (3,042)	$ (1,575)

(1) Included in "Right-of-use lease assets" on the consolidated balance sheet.
(2) Included in "Accounts payable and accrued liabilities" on the consolidated balance sheet.
(3) Included in "Lease liabilities" on the consolidated balance sheet.

The Company's leases generally do not provide an implicit rate, and therefore the Company uses its incremental borrowing rate as the discount rate when measuring operating lease liabilities. The incremental borrowing rate represents an estimate of the interest rate the Company would incur at lease commencement to borrow an amount equal to the lease payments on a collateralized basis over the term of a lease. For operating leases existing prior to January 1, 2019, the incremental borrowing rate as of January 1, 2019 was used for the remaining lease term.

The table below presents the weighted average remaining lease terms and weighted average discount rates for the Company's leases as of December 31, 2020 and December 31, 2019:

	December 31, 2020	December 31, 2019
Weighted Average Remaining Lease Terms (in years):		
Operating leases	1.47	2.16
Financing leases	3.24	3.14
Weighted Average Discount Rate:		
Operating leases	5.72%	6.04%
Financing leases	5.92%	6.24%

Maturities for the Company's lease liabilities on the consolidated balance sheet as of December 31, 2020, were as follows (in thousands):

	December 31, 2020	
	Operating Leases	Financing Leases
2021	$ 1,906	$ 1,094
2022	240	980
2023	170	823
2024	158	459
Total future minimum lease payments	2,474	3,356
Less: imputed interest	(120)	(314)
Present value of lease liabilities	$ 2,354	$ 3,042

The following table summarizes expenses related to the Company's leases for the three months ended December 31, 2020 and December 31, 2019 (in thousands):

	Three Months Ended December 31, 2020	Three Months Ended December 31, 2019
Operating lease cost (1) (2)	$ 843	$ 542
Financing lease cost - amortization of right-of-use assets	231	87
Financing lease cost - interest on lease liabilities	47	17
Administrative lease cost (3)	19	19
Short-term lease cost (1) (4)	360	741
Total lease cost	$ 1,500	$ 1,406

(1) This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.
(2) Costs related to office leases and compressors with lease terms of twelve months of more.
(3) Costs related primarily to office equipment and IT solutions with lease terms of more than one month and less than one year.
(4) Costs related primarily to drilling rigs, generators and compressor agreements with lease terms of more than one month and less than one year.

The following table summarizes expenses related to the Company's leases for the years ended December 31, 2020 and December 31, 2019 (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Operating lease cost (1) (2)	$ 3,055	$ 742
Financing lease cost - amortization of right-of-use assets	642	92
Financing lease cost - interest on lease liabilities	131	18
Administrative lease cost (3)	75	75
Short-term lease cost (1) (4)	1,974	4,101
Total lease cost	$ 5,877	$ 5,028

(1) This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.
(2) Costs related to office leases and compressors with lease terms of twelve months of more. Higher costs in 2020 due to additional leases related to the properties acquired from Will Energy and White Star during the three months ended December 31, 2019.
(3) Costs related primarily to office equipment and IT solutions with lease terms of more than one month and less than one year.
(4) Costs related primarily to drilling rigs, generators and compressor agreements with lease terms of more than one month and less than one year.

There were $3.2 million and $0.9 million in cash payments related to operating leases and financing leases, respectively, during the year ended December 31, 2020. There were $0.8 million and $0.1 million in cash payments related to operating leases and financing leases, respectively, during the year ended December 31, 2019.

10. Other Financial Information

The following table provides additional detail for accounts receivable, prepaids and accounts payable and accrued liabilities which are presented on the consolidated balance sheets (in thousands):

	December 31, 2020	December 31, 2019
Accounts receivable:		
Trade receivables	$ 20,306	$ 21,110
Receivable for Alta Resources distribution	1,712	1,712
Joint interest billings	15,637	13,104
Income taxes receivable	268	509
Other receivables	2,209	4,126
Allowance for doubtful accounts [1]	(2,270)	(994)
Total accounts receivable	$ 37,862	$ 39,567
Prepaid Expenses:		
Prepaid insurance	$ 2,825	$ 683
Other [2]	535	508
Total Prepaid Expenses	$ 3,360	$ 1,191
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 23,701	$ 15,905
Legal suspense related to revenues [3]	27,983	33,739
Advances from partners [4]	76	6,733
Accrued exploration and development [4]	490	8,210
Trade payables	14,273	14,086
Accrued general and administrative expenses [5]	6,191	12,037
Accrued operating expenses	5,755	5,794
Accrued operating and finance leases	2,772	3,120
Other accounts payable and accrued liabilities	2,729	4,969
Total accounts payable and accrued liabilities	$ 83,970	$ 104,593

(1) Increase in 2020 primarily due to the additional properties acquired from Will Energy and White Star.
(2) Other prepaids primarily includes software licenses.
(3) Suspended revenues primarily relate to amounts for which there is some question as to valid ownership, unknown addresses of payees or some other payment dispute.
(4) Decrease in 2020 due to a decrease in drilling and completion activity. In response to the dramatic decline in commodity prices in the first quarter of 2020, the Company suspended further operated drilling in its West Texas area, and in its other onshore areas.
(5) The December 31, 2019 balance includes an accrual of $6.3 million for a legal judgment that was paid in April 2020. See Note 14 – “Commitment and Contingencies” for further information.

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the years ended December 31, 2020 and 2019, in thousands:

	Year Ended December 31,	
	2020	2019
Cash payments:		
Interest payments	$ 3,592	$ 7,761
Income tax payments, net of cash refunds	293	668
Non-cash items excluded from investing activities in the consolidated statements of cash flows:		
Increase (decrease) in accrued capital expenditures	(7,615)	1,841

11. Investment in Exaro Energy III LLC

Through the Company's wholly-owned subsidiary, Contaro Company ("Contaro"), the Company committed to invest up to $67.5 million in Exaro for an ownership interest of approximately 37%. The aggregate commitment of all the Exaro investors was approximately $183 million. The Company did not make any contributions during the year ended December 31, 2020 and has no plans to invest additional funds in Exaro, as the commitment to invest in Exaro expired on March 31, 2017. As of December 31, 2020, the Company had invested approximately $46.9 million. Contango's share in the equity of Exaro at December 31, 2020 was approximately $6.8 million.

The Company's share in Exaro's results of operations recognized for the years ended December 31, 2020 and 2019 was a gain of approximately $27,000, net of zero tax expense and a gain of approximately $1.0 million, net of zero tax, respectively.

12. Asset Retirement Obligation

The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

Activities related to the Company's ARO during the years ended December 31, 2020 and 2019 were as follows (in thousands):

	Year Ended December 31,	
	2020	2019
Balance as of the beginning of the period	$ 51,665	$ 13,497
Liabilities incurred during period	5	256
Liabilities settled during period	(338)	(1,380)
Accretion	2,702	1,062
Sales	(5,239)	(816)
Acquisitions	—	37,596
Change in estimate	3,978	1,450
Balance as of the end of the period	$ 52,773	$ 51,665

All of the total liabilities incurred during the years ended December 31, 2020 and 2019 were related to new wells drilled during the period. All of the total liabilities settled during the years ended December 31, 2020 and 2019 were related to wells plugged and abandoned during the period. The acquisitions refer to new liabilities assumed from the properties acquired in 2019 from White Star and Will Energy. The change in estimate relates to year-end adjustments for updated estimated plugging and abandonment costs, primarily in the Company's Central Oklahoma and Western Anadarko regions.

13. Long-Term Debt

Credit Agreement

On September 17, 2019, the Company entered into its new revolving Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders, which established a borrowing base of $65 million.

The borrowing base is subject to semi-annual redeterminations which will occur on or around May 1st and November 1st of each year. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy Acquisition and White Star Acquisition, to add two additional lenders and increase the borrowing base thereunder to $145 million. On June 9, 2020, the Company entered into the Second Amendment to the Credit Agreement (the "Second Amendment"). The Second Amendment redetermined the borrowing base at $95 million, among other things, pursuant to the regularly scheduled redetermination process. The Second Amendment also provided for further $10 million automatic reductions in the borrowing base on each of June 30, 2020 and September 30, 2020. On October 30, 2020, the Company entered into the Third Amendment to the Credit Agreement, which became effective on January 21, 2021, upon the satisfaction of certain conditions, including the consummation of the Mid-Con Acquisition. See Note 4 – "Acquisitions and Dispositions" for more information. The Third Amendment provided for, among other things, (i) a 25 basis point increase in the applicable margin at each level of the borrowing base utilization-based pricing grid, (ii) an increase of the borrowing base to $130.0 million on the effective date of the Third Amendment with a $10.0 million automatic stepdown in the borrowing base on March 31, 2021, (iii) certain modifications to the Company's minimum hedging covenant including requiring hedging for at least 75% of the Company's projected PDP volumes for 24 full calendar months on or prior to 30 days after the effective date of the Third Amendment and on April 1 and October 1 of each calendar year, (iv) addition of three new lenders to the lender group. As of December 31, 2020, the borrowing base was $75 million. In connection with the closing of the Mid-Con Acquisition on January 21, 2021, the borrowing base increased automatically to $130.0 million. The next regularly scheduled borrowing base redetermination is on or before May 1, 2021.

Initially, the Company incurred $1.8 million of arrangement and upfront fees in connection with the Credit Agreement and incurred an additional $1.6 million in fees for the first amendment to the Credit Agreement, all to be amortized over the remaining term of the Credit Agreement. No fees were incurred for the Second Amendment; however, during the three months ended June 30, 2020, the Company expensed $1.0 million of the debt issuance costs discussed above, which originally were to be amortized over the life of the loan, due to the reduction in the borrowing base per the Second Amendment. The Company initially incurred $0.1 million in fees related to the Third Amendment during the three months ended December 31, 2020. During the year ended December 31, 2020, the Company amortized debt issuance costs of $1.6 million related to the Credit Agreement, including the $1.0 million mentioned above. As of December 31, 2020, the remaining balance of these fees was $1.8 million, which will be amortized through September 17, 2024. In January 2021, the Company incurred an additional $0.9 million in fees related to the Third Amendment that became effective on January 21, 2021, in connection with the closing of the Mid-Con Acquisition. These fees will also be amortized over the remaining term of the loan.

As of December 31, 2020, the Company had $9.0 million outstanding under the Credit Agreement and $1.9 million in outstanding letters of credit. As of December 31, 2019, the Company had $72.8 million outstanding under the Credit Agreement and $1.9 million in outstanding letters of credit. As of December 31, 2020, borrowing availability under the Credit Agreement was $64.1 million.

The Credit Agreement is collateralized by liens on substantially all of the Company's oil and natural gas properties and other assets and security interests in the stock of its wholly owned and/or controlled subsidiaries. The Company's wholly owned and/or controlled subsidiaries are also required to join as guarantors under the Credit Agreement.

Borrowings under the Credit Agreement bear interest at LIBOR, the U.S. prime rate, or the federal funds rate, plus a 1.75% to 3.75% margin, dependent upon the amount outstanding. Total interest expense under the Company's Credit Agreement, including commitment fees, the additional $1.0 million in expensed loan fees discussed above and other financing fees was approximately $5.0 million for the year ended December 31, 2020. Total interest expense under the Company's current and previous credit agreements, including commitment fees and other financing fees, was approximately $8.6 million for the year ended December 31, 2019.

The weighted average interest rates in effect at December 31, 2020 and December 31, 2019 were 2.9% and 4.3% under the Credit Agreement, respectively.

The Credit Agreement contains customary and typical restrictive covenants. The Credit Agreement requires a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Agreement. The Second Amendment includes a waiver of the Current Ratio requirement until the quarter ending March 31, 2022. Additionally, the Second Amendment, among other things, provides for an increase in the Applicable Margin grid on borrowings outstanding of 50 basis points, and includes provisions requiring monthly aged accounts payable reports and typical anti-cash hoarding and cash sweep provisions with respect to a consolidated cash balance in excess of $5.0 million. The Credit Agreement also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, a going concern qualification, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events. As of December 31, 2020, the Company was in compliance with all of its covenants under the Credit Agreement.

Paycheck Protection Program Loan

On April 10, 2020, the Company entered into a promissory note evidencing an unsecured loan in the amount of approximately $3.4 million (the “PPP Loan”) made to the Company under the Paycheck Protection Program (the “PPP”). The PPP was established under the Coronavirus Aid, Relief, and Economic Security Act (“CARES Act”), signed into law on March 27, 2020, and is administered by the U.S. Small Business Administration. The PPP Loan to the Company is being made through JPMorgan Chase Bank, N.A and is included in “Long-Term Debt” on the Company’s consolidated balance sheet.

The PPP Loan matures on the two-year anniversary of the funding date and bears interest at a fixed rate of 1.00% per annum. Monthly principal and interest payments, less the amount of any potential forgiveness (discussed below), will commence after the six-month anniversary of the funding date. The promissory note evidencing the PPP Loan provides for customary events of default, including, among others, those relating to failure to make payment, bankruptcy, breaches of representations and material adverse effects. The Company may prepay the principal of the PPP Loan at any time without incurring any prepayment charges.

Under the terms of the CARES Act, PPP loan recipients can apply for and be granted forgiveness for all or a portion of the loans granted under the PPP, subject to an audit. Under the CARES Act, loan forgiveness is available, subject to limitations, for the sum of documented payroll costs, covered mortgage interest payments, covered rent payments and covered utilities during either: (1) the eight-week period beginning on the funding date; or (2) the 24-week period beginning on the funding date. Forgiveness is reduced if full-time employee headcount declines, or if salaries and wages for employees with salaries of $100,000 or less annually are reduced by more than 25%. The Company utilized the PPP Loan amount for qualifying expenses during the 24-week coverage period, and on September 30, 2020, submitted its application for forgiveness of all of the PPP Loan in accordance with the terms of the CARES Act and related guidance. The Company is currently awaiting a response from the Small Business Administration. In the event the PPP Loan or any portion thereof is forgiven, the amount forgiven is applied to the outstanding principal.

14. Commitments and Contingencies

Contango leases its office space, compressors, vehicles and certain other equipment, which are considered operating and finance leases. See Note 9 – “Leases” for more information. The Company also incurs commitments on its oil and natural gas leases, such as delay rentals, surface damage payments and rental payments associated with salt water disposal contracts.

As of December 31, 2020, minimum future operating and finance lease payments and other commitments listed above for Contango's fiscal years are as follows (in thousands):

Fiscal years ending December 31,	
2021	$ 3,941
2022	2,163
2023	1,872
2024	1,496
2025 and thereafter	879
Total	$ 10,351

The amounts incurred under operating and finance leases and payments related to delay rentals, surface use and salt water disposal contracts during the years ended December 31, 2020 and 2019 were approximately $4.3 million and $1.5 million, respectively. The increase in 2020 payments is due to the properties acquired in the Will Energy Acquisition and the White Star Acquisition.

Throughput Contract Commitment

The Company had a signed a throughput agreement with a third-party pipeline owner/operator that constructed a natural gas gathering pipeline in Southeast Texas that allowed the Company to defray the cost of building the pipeline itself. Beginning in late 2016, the Company was unable to meet the minimum monthly gas volume deliveries through this line in Southeast Texas and continued to not meet the minimum throughput requirements under the agreement through the expiration of the throughput commitment on March 31, 2020. As of December 31, 2019, the Company recorded a $1.0 million loss contingency through the end of the contract in March 2020, which was paid in three equal monthly installments in 2020. As the remaining throughput commitment fees of $1.0 million were accrued during the year ended December 31, 2019, the Company incurred no expense related to this commitment in 2020.

Legal Proceedings

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decades-old poorly documented transactions. Based on prior summary judgments, the trial court entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. In early October 2019, the Texas Supreme Court notified the Company that it would not hear this case. The Company engaged additional legal representation to assist in the preparation of an amended petition requesting that the Texas Supreme Court reconsider its initial decision to not review the case. That amended petition was filed, and in mid-March 2020, the Texas Supreme Court decided they would not re-hear the case. Consequently, during the three months ended December 31, 2019, the Company recorded a $6.3 million liability for the judgment, interest and fees, with $3.5 million of such liability related to suspended funds reflected in "Accounts payable and accrued liabilities" on the Company's consolidated balance sheet for the year ended December 31, 2019. The judgment, interest and fees were paid in April 2020.

On January 14, 2016, the Company was named as the defendant in a lawsuit filed in the District Court for Harris County in Texas by a third-party operator. The Company participated in the drilling of a well in 2012, which experienced serious difficulties during the initial drilling, which eventually led to the plugging and abandoning of the wellbore prior to reaching the target depth. In dispute is whether the Company is responsible for the additional costs related to the drilling difficulties and plugging and abandonment. In September 2019, the case went to trial, and, in

October 2019, the court ruled in favor of the plaintiff. Prior to the judgment, the Company had approximately $1.1 million in accounts payable related to the disputed costs associated with this case. As a result of the judgment, during the three months ended September 30, 2019, the Company recorded an additional $2.1 million liability for the final judgment plus fees and interest. The Company also prepared and filed an appeal with the appellate court for a review of the initial trial court decision The plaintiff petitioned the appellate court for an extension of time to file briefs with the court until late in the fourth quarter of 2020. On January 23, 2021, the appellate court notified both parties that it would begin reviewing the merits of the case beginning on February 23, 2021. On March 3, 2021, the appellate court affirmed the trial court’s decision. The Company plans to appeal the decision to the Supreme Court.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

15. Net Loss Per Common Share

A reconciliation of the components of basic and diluted net loss per common share for the years ended December 31, 2020 and 2019 is presented below (in thousands):

	Year Ended December 31, 2020		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (165,342)	137,522	$ (1.20)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (165,342)	137,522	$ (1.20)

	Year Ended December 31, 2019		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (159,796)	54,136	$ (2.95)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (159,796)	54,136	$ (2.95)

The numerator for basic earnings per share is net loss attributable to common stockholders. The numerator for diluted earnings per share is net loss available to common stockholders.

Potential dilutive securities (stock options, restricted stock and PSUs) have not been considered when their effect would be antidilutive. The potentially dilutive shares would have been 529,508 shares and 613,506 shares for the years ended December 31, 2020 and 2019, respectively.

16. Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. The Company is subject to taxation in several jurisdictions, and the calculation of its tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Income Tax Computation

Actual income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate rate of 21 percent for the years ended December 31, 2020 and 2019, respectively, to pretax income as follows (dollars in thousands):

	Year Ended December 31,			
	2020		2019	
Benefit at statutory tax rate	$ (34,663)	21.00 %	$ (33,561)	21.00 %
State income tax provision, net of federal benefit	467	(0.28)%	555	(0.35)%
State deferred tax benefit	(5,553)	3.36 %	—	— %
Permanent differences	26	(0.02)%	30	(0.02)%
Stock based compensation	81	(0.05)%	979	(0.61)%
Valuation allowance	40,059	(24.27)%	34,239	(21.42)%
Other	330	(0.20)%	(2,022)	1.26 %
Income tax provision	$ 747	(0.46)%	$ 220	(0.14)%

The effective tax rate for the years ended December 31, 2020 and 2019 varies from the statutory rate primarily as a result of recording a valuation allowance.

The provision (benefit) for income taxes for the periods indicated are comprised of the following (in thousands):

	Year Ended December 31,	
	2020	2019
Current tax provision (benefit):		
Federal	$ 275	$ (335)
State	472	555
Total	$ 747	$ 220
Deferred tax benefit:		
Federal	$ —	$ —
State	—	—
Total	$ —	$ —
Total tax provision (benefit):		
Federal	$ 275	$ (335)
State	472	555
Total	$ 747	$ 220
Included in gain from investment in affiliates	$ —	$ —
Total income tax provision	$ 747	$ 220

The Federal income tax expense results from an adjustment in the previous period of the credit for Alternative Minimum Tax (“AMT”) paid in prior years. As a result of the tax reform in 2017, the corporate AMT was repealed, and any AMT credit was made refundable. The first half of the credit was refunded when the Company filed its 2018 federal income tax return, and the second half of the credit was refunded when the Company filed its 2019 federal tax return. The CARES Act modified the timing of these refunds, allowing the Company to request an expedited refund of $0.3

million during the quarter ended June 30, 2020. This amount was previously accounted for as an income tax benefit when the corporate AMT was repealed. State income tax expense relates to income taxes for the quarter and the nine months which are expected to be owed to the states of Louisiana and Oklahoma resulting from activities within those states and, in each case, that are not shielded by existing Federal tax attributes.

Additionally, under the CARES Act, the Company will benefit from an amendment to Internal Revenue Code Section 163(j) that temporarily increases deductible interest expense limitations. Specifically, the CARES Act increases the 30% Adjusted Taxable Income ("ATI") limitation to 50% of ATI for taxable years beginning in each of 2019 and 2020. This will have the effect of allowing the Company to use a Section 163(j) carryover from the prior year that was not limited by Section 382 (discussed below). The Company does not expect to benefit from any other income tax-related provisions of the CARES Act.

The net deferred tax is comprised of the following (in thousands):

	December 31, 2020	December 31, 2019
Deferred tax assets:		
Net operating loss carryforward	$ 84,982	$ 80,617
Deferred compensation	447	—
Derivative instruments	—	377
State deferred tax assets	6,507	954
Oil and gas properties	39,081	11,436
Investment in affiliates	752	2,799
Recognized built in loss carryforward	9,987	6,718
163(j) Carryforward	1,828	1,585
Other	1,796	964
Total deferred tax assets before valuation allowance	$ 145,380	$ 105,450
Valuation allowance	(145,269)	(105,212)
Net deferred tax assets	$ 111	$ 238
Deferred tax liability:		
Deferred compensation	$ —	$ (238)
Derivative instruments	(111)	—
Deferred tax liability	$ (111)	$ (238)
Total net deferred tax	$ —	$ —

Accounting for uncertainty in income taxes prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities.

In assessing the realizability of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. The Company considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the amount of deferred tax liabilities, level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, the Company believes it is not more-likely-than-not that it will realize the benefits of these deductible differences and has recorded a valuation allowance for federal and state purposes of approximately $138.8 million and approximately $6.5 million, respectively.

As of December 31, 2020, the Company had federal net operating loss ("NOL") carryforwards of approximately $404.7 million and state NOLs of $26.4 million. The Federal NOL carryforwards are made up of: (i) those acquired in the merger with Crimson Exploration, Inc. ("Crimson") in 2013 (the "Merger") and (ii) from subsequent taxable losses during the years 2014 through 2020 due to lower commodity prices and utilization of various elections available to the Company in expensing capital expenditures incurred in the development of oil and natural gas properties. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Internal Revenue Code Section 382 related to changes of more than 50% of ownership of the Company's stock by 5% or greater shareholders over a three-year period (a Section 382 Ownership Change) from the time of such an ownership change. Recently passed legislation, however, temporarily suspends the Section 172 limitation for NOLs arising in a tax year beginning in 2018, 2019 or 2020 and also allows these NOLs to be carried back five years.

On November 19, 2018, the Company completed a follow-on offering (the "2018 Offering") of 7.5 million additional shares of common stock. Prior to December 18, 2018, the underwriters exercised their Green Shoe option purchasing an additional approximate 1.1 million shares, resulting in a total of approximately 8.6 million primary shares issued in the Offering. This issuance resulted in a Section 382 Ownership Change (the "2018 Ownership Change") which limits the Company's future ability to use its NOLs. As such, the Company is limited in use of NOLs for amounts incurred prior to November 20, 2018 in an amount estimated to be approximately $2.4 million per year (plus any recognized built in gains during the next five years) or until expiration of each annual vintage of NOL (generally, 20 years for each annual vintage of NOLs incurred prior to 2018).

On September 12, 2019, as discussed in Note 1 – "Organization and Business", the Company completed the September 2019 Public Offering which also resulted in a Section 382 Ownership Change on that date (the "2019 Ownership Change" and, together with the 2018 Ownership Change, the "Ownership Changes"). Due to changing market conditions, the Company's ability to utilize pre-2018 NOLs on that date could be limited to $700,000 a year (in pre-tax dollars). This lower annual limitation resulting from the 2019 Ownership Change effectively eliminates the ability to utilize these tax attributes in the future.

The Company is also affected by the limitation in Section 163(j) on interest taken in any given tax year. As of December 31, 2020, the Company had a limitation of $2.4 million which will carry over indefinitely. Additionally, the Company's post-2017 NOLs of $132.7 million are also not subject to expiration, but are limited to offsetting 80% of the Company's taxable income in any year of usage after December 31, 2020. These carryovers are subject to any applicable Section 382 limitation (discussed above).

As a result of the Ownership Changes, the Company has recorded a valuation allowance against substantially all of its NOLs and other deferred tax assets. The valuation allowance balance at December 31, 2020 is $145.3 million.

ASC 740, Income Taxes ("ASC 740") prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As a result of the Merger, the Company acquired certain tax positions taken by Crimson in prior years. These positions are not expected to have a material impact on results of operations, financial position or cash flows. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows (in thousands):

	Unrecognized Tax Benefits
Balance at December 31, 2019	$ —
Additions based on tax positions related to the current year	—
Additions based on tax positions related to prior years	—
Additions due to acquisitions	—
Reductions due to a lapse of the applicable statute of limitations	—
Change in rate due to remeasurement	—
Balance at December 31, 2020	$ —

The Company's policy is to recognize interest and penalties related to uncertain tax positions as income tax benefit (expense) in the Company's consolidated statements of operations. The Company had no interest or penalties related to unrecognized tax benefits for the year ended December 31, 2020 or any prior years. The total amount of unrecognized tax benefit, if recognized, that would affect the effective tax rate was zero.

Generally, the Company's income tax years of 2009 through 2020 remain open and subject to examination by Federal tax authorities, and the tax years of 2009 through 2020 remain open and subject to examination by the tax authorities in Texas, Louisiana and Oklahoma, which are the jurisdictions where the Company carries its principal operations. These audits can result in adjustments of taxes due or adjustments of the NOL carryforwards that are available to offset future taxable income. The Company currently has no ongoing tax audits and has not been notified of pending activity by taxing jurisdictions. The Company does not anticipate that the total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of the statute of limitations prior to December 31, 2020.

17. Subsequent Events

Mid-Con Acquisition

On January 21, 2021, the Company closed the Mid-Con Acquisition in an all-stock merger transaction. At the time of close, each common unit representing limited partner interests in Mid-Con issued and outstanding (other than treasury units or units held by Mid-Con GP) was converted automatically into the right to receive 1.75 shares of the Company's common stock. A total of 25,409,164 shares of Contango common stock were issued at the closing of the Mid-Con Acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

Silvertip Acquisition

On February 1, 2021, the Company closed the Silvertip Acquisition to acquire certain oil and natural gas properties located in the Big Horn Basin in Wyoming and Montana, in the Powder River Basin in Wyoming and in the Permian Basin in Texas and New Mexico, for aggregate consideration of approximately $58 million in cash. The Company previously paid a $7.0 million deposit during the three months ended December 31, 2020, in connection with the execution of the purchase agreement, and a balance of $46.2 million was paid upon closing of the Silvertip Acquisition, after customary closing adjustments, including the results of operations during the period between the effective date of August 1, 2020 and the closing date. See Note 4 – "Acquisitions and Dispositions" for more information.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited)

In accordance with U.S. GAAP for disclosures regarding oil and natural gas producing activities, and SEC rules for oil and natural gas reporting disclosures, we are making the following disclosures regarding our oil and natural gas reserves and exploration and production activities.

Capitalized Costs Related to Oil and Natural Gas Producing Activities

The following table presents information regarding our net capitalized costs related to oil and natural gas producing activities as of the date indicated (in thousands):

	December 31,	
	2020	2019
Proved oil and gas properties	$ 1,274,508	$ 1,306,916
Unproved oil and gas properties	16,201	27,619
	1,290,709	1,334,535
Less accumulated depreciation, depletion, amortization and impairment	(1,190,359)	(1,043,668)
Net capitalized costs	$ 100,350	$ 290,867

Costs Incurred

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,	
	2020	2019
Property acquisition costs:		
Unproved	$ 1,508	$ 12,486
Proved	—	168,838
Exploration costs	11,594	1,003
Development costs	5,819	41,273
Total costs incurred	$ 18,921	$ 223,600

Oil and Natural Gas Reserves

Proved reserves are the estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and current regulatory practices. Proved developed reserves are proved reserves which are expected to be produced from existing completion intervals with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2020, 2019 and 2018, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. and Netherland, Sewell & Associates, Inc. All estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The below table summarizes the Company's net ownership interests in estimated quantities of proved oil, natural gas and natural gas liquids ("NGLs") reserves and changes in net proved reserves as of December 31, 2020, 2019 and 2018, all of which are located in the continental United States.

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (Mboe)
Proved Developed and Undeveloped Reserves as of:				
December 31, 2018	9,434	54,206	3,517	21,985
Sale of minerals in place	(1)	(371)	(12)	(75)
Acquisitions	7,718	91,765	9,103	32,115
Extensions and discoveries	9,788	9,581	1,457	12,842
Revisions of previous estimates	(7,063)	(14,359)	(1,689)	(11,146)
Production	(791)	(9,522)	(612)	(2,990)
December 31, 2019	19,085	131,300	11,764	52,731
Sale of minerals in place	(142)	(4,754)	(238)	(1,172)
Acquisitions	—	—	—	—
Extensions and discoveries	2,074	423	184	2,328
Revisions of previous estimates	(6,339)	(23,520)	(3,294)	(13,552)
Production	(1,674)	(18,967)	(1,262)	(6,097)
December 31, 2020	13,004	84,482	7,154	34,238
Proved Developed Reserves as of:				
December 31, 2018	3,103	46,840	2,297	13,206
December 31, 2019	9,819	122,691	10,484	40,752
December 31, 2020	7,166	82,788	6,595	27,558
Proved Undeveloped Reserves as of:				
December 31, 2018	6,331	7,366	1,220	8,779
December 31, 2019	9,266	8,609	1,280	11,979
December 31, 2020	5,838	1,694	559	6,680

During the year ended December 31, 2020, our proved reserves decreased by approximately 18.5 MMBoe primarily due to a 21.1 MMBoe decrease related to negative revisions related to lower commodity prices, a 1.0 MMBoe decrease related to property sales in our Central Oklahoma and Western Anadarko regions and 2020 production of 6.1 MMBoe, partially offset by a 7.5 MMBoe increase related to positive performance revisions primarily in our Central Oklahoma and West Texas regions and a 2.3 MMBoe increase attributable to new PUD locations in our West Texas area.

During the year ended December 31, 2019, our proved reserves increased by approximately 30.7 MMBoe primarily due to the 32.1 MMBoe increase related to the White Star Acquisition and Will Energy Acquisition, as well as an increase in total reserves attributable to our recently drilled wells in the NE Bullseye area of West Texas, offset by 2019 production and a downward revision in Bullseye PUDs in West Texas related to the impact of the low commodity price environment on economics in the area, and the related timeline for expected development of those PUD locations over the next five years.

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved oil and natural gas reserves as of December 31, 2020 and 2019 are shown below (in thousands):

	As of December 31,	
	2020	**2019**
Future cash inflows	$ 721,395	$ 1,519,882
Future production costs	(411,069)	(782,031)
Future development costs	(101,723)	(217,782)
Future income tax expenses	(18,901)	(43,913)
Future net cash flows	189,702	476,156
10% annual discount for estimated timing of cash flows	(74,115)	(218,314)
Standardized measure of discounted future net cash flows	$ 115,587	$ 257,842

Future cash inflows represent expected revenues from production and are computed by applying certain prices of oil and natural gas to estimated quantities of proved oil and natural gas reserves. Prices are based on the first-day-of-the-month prices for the previous 12 months. As of December 31, 2020, future cash inflows were based on unadjusted prices of $39.57 per barrel of oil, $2.14 per MMBtu of natural gas and $12.43 per barrel of NGL. As of December 31, 2019, future cash inflows were based on unadjusted prices of $55.69 per barrel of oil, $2.52 per MMBtu of natural gas and $16.95 per barrel of NGL.

Realized Prices

The average realized prices for the year ended December 31, 2020 production were $37.31 per barrel of oil, $1.65 per MCF of gas and $13.54 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $25.3 million for the year ended December 31, 2020.

The average realized prices for the year ended December 31, 2019 production were $56.55 per barrel of oil, $2.35 per MCF of gas and $15.39 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $2.6 million for the year ended December 31, 2019.

Future production and development costs are estimated expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves based on historical costs and assuming continuation of existing economic conditions. Future development costs relate to compression charges at our platforms, abandonment costs, recompletion costs and additional development costs for new facilities.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates of oil and natural gas producing operations.

Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below (in thousands):

	Year Ended December 31,	
	2020	2019
Changes in standardized measure due to current year operation:		
Sales of oil and natural gas produced during the period, net of production expenses	$ (68,787)	$ (55,868)
Extensions and discoveries	4,729	54,308
Net change in prices and production costs	(78,046)	(67,470)
Changes in estimated future development costs	9,360	16,223
Revisions in quantity estimates	(48,609)	(77,309)
Purchase of reserves	—	177,007
Sale of reserves	(3,259)	(246)
Previously estimated development costs incurred	—	2,958
Accretion of discount	28,655	22,051
Changes in income taxes	17,922	(27,148)
Change in the timing of production rates and other	(4,220)	(5,608)
Net change	(142,255)	38,898
Beginning of year	257,842	218,944
End of year	$ 115,587	$ 257,842

During the year ended December 31, 2020, our proved reserves decreased by approximately 18.5 MMBoe, and our standardized measure decreased by approximately $142.3 million. This decrease is primarily attributable to lower commodity prices and the sales of non-core producing assets.

During the year ended December 31, 2019, our proved reserves increased by approximately 30.7 MMBoe, and our standardized measure increased by approximately $38.9 million. This increase is primarily attributable to the Will Energy Acquisition and White Star Acquisition.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations

The following table sets forth the results of operations by quarter for the fiscal years ended December 31, 2020 and 2019 (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
Year ended December 31, 2020:				
Revenues	$ 34,573	$ 17,842	$ 31,348	$ 29,157
Operating Loss [1]	$ (151,465)	$ (21,275)	$ 2,058	$ (24,614)
Net loss attributable to common stock [2]	$ (105,255)	$ (28,034)	$ (6,805)	$ (25,248)
Net loss per share [3]:				
Basic:	$ (0.80)	$ (0.21)	$ (0.05)	$ (0.16)
Diluted:	$ (0.80)	$ (0.21)	$ (0.05)	$ (0.16)
Year ended December 31, 2019:				
Revenues	$ 14,011	$ 12,762	$ 12,547	$ 37,193
Operating Loss [1]	$ (4,553)	$ (6,457)	$ (8,794)	$ (130,926)
Net loss attributable to common stock [2]	(8,618)	(4,961)	(7,838)	(138,379)
Net loss per share [3]:				
Basic:	$ (0.26)	$ (0.15)	$ (0.19)	$ (1.32)
Diluted:	$ (0.26)	$ (0.15)	$ (0.19)	$ (1.32)

(1) Represents oil, natural gas and NGL sales and fee for service revenues, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of oil and natural gas properties and general and administrative expense.

(2) Represents oil, natural gas and NGL sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of oil and natural gas properties, general and administrative expense, and other income and expense after income taxes.

(3) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income for that quarter and the weighted average number of common shares outstanding during that quarter.

Company Information

Our mission is to maintain a team committed to those values and standards in promoting Contango as an industry leader built on win/win relationships.

Outside Counsel

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Common Stock Information

Contango is listed on the NYSE American Stock Exchange under the symbol "MCF."

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Auditors

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Houston, TX 77002

Form 10-K

Additional copies of the Form 10-K as filed with the SEC, are available at our website (contango.com) under Investor Relations.

Board of Directors

JOHN C. GOFF
Chairman of the Board

WILKIE S. COLYER, JR
CEO

B.A. BERILGEN
Chairman of the Nominating Committee

ELLIS L. MCCAIN
Chairman of the Audit Committee

JANET PASQUE

JOSEPH J. ROMANO
President & CEO Olympic Energy Partners, Chairman of the Compensation Committee

KAREN SIMON

Management Team

WILKIE S. COLYER, JR
CEO

W. FARLEY DAKAN
President

E. JOSEPH GRADY
SVP & CFO

CHAD R. ROLLER
SVP & COO

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Contango

2020 ANNUAL REPORT

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NYSE AMERICAN : MCF