CALLON
PETROLEUM

Embracing change. Delivering results.

CALLON PETROLEUM | 2020 ANNUAL REPORT

About Callon

Callon Petroleum is an independent oil and natural gas company focused on the acquisition, exploration, and development of high-quality assets in the leading oil plays of the Permian Basin in West Texas and Eagle Ford Shale in South Texas. Our mission is to build trust, create value, and drive sustainable growth for our investors, our employees, and the communities in which we operate.

2020 Highlights

>$120 MM

ADJUSTED FREE CASH FLOW GENERATION[1]

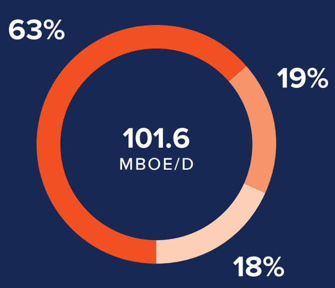
$19/BOE

FULL-YEAR ADJUSTED EBITDA[1]

>$300 MM

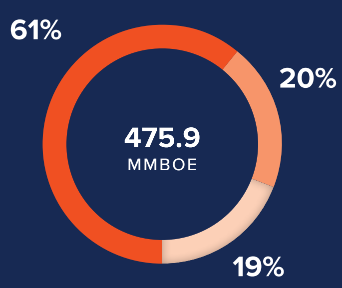
REDUCTION IN ABSOLUTE DEBT FROM MONETIZATIONS AND DEBT EXCHANGE

2020 Production



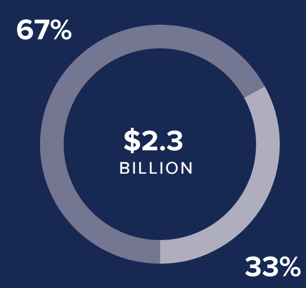
- OIL MBBL/D
- NGL MBBL/D
- GAS MBOE/D

2020 Reserves



- OIL MMBBLS
- NGL MMBBLS
- GAS MMBOE

2020 PV-10[2]



- PDP BN
- PUD BN

[1]Total adjusted free cash flow from 2Q – 4Q 2020. Adjusted free cash flow is defined as Adjusted EBITDA minus the sum of operational capital, capitalized interest, capitalized G&A, and net interest expense. Both Adjusted free cash flow and Adjusted EBITDA are non-GAAP financial measures; please refer to appendix for reconciliation of Non-GAAP financial measures.

[2]Please see reconciliation of PV-10, a Non-GAAP financial measure, on page 10 of the Company's 2020 Form 10-K.

To Our Shareholders

For the oil and gas industry, 2020 will be marked by the extraordinary volatility in commodity prices created by the OPEC price war that was further exacerbated by the COVID-19 pandemic, as well as the institution of remote working in an industry known for collaborative teamwork across multiple entities. Our response to the unprecedented challenge was swift and decisive.

First, we implemented measures to protect the health and safety of our employees and their families. Second, we established a business continuity program to keep our operations running smoothly while transitioning our office-based teams to a completely remote work environment. Finally, we began implementing changes to our operations, revising our development plans, and sought ways to preserve liquidity and reduce costs to mitigate potential impacts from the collapsing commodity environment.

While the dramatic decline in oil prices led to significant reduction in industry-wide activity, our rapid reduction in drilling and completion activity resulted in a more flexible operational plan that created opportunities for optimizing our balance sheet. Leveraging the optionality presented by our diverse portfolio of larger, longer cycle projects and shorter cycle, immediate cash flow generating projects, we were able to restructure capital outlays, creating opportunities to offset the production decline associated with activity deferrals. While adjusting for this new commodity outlook, our teams remained engaged in seeking environmentally beneficial and operationally efficient cost reduction options. Because of our thoughtful approach, we were able to achieve a number of initiatives that had a positive effect on both our margins and our surrounding communities:

- Generated over $120 million of adjusted free cash flow[1] ("FCF") during the last three quarters of the year, resulting in a positive FCF position for the full year
- Posted annual adjusted EBITDA[2] of over $700 million despite a drop of more than 40% in average realized prices compared to the prior year
- Issued $300 million in new second lien notes, providing a meaningful increase in liquidity
- Exchanged $389 million of our existing senior notes for second lien notes, reducing our long-term debt outstanding by $172 million
- Completed an overriding royalty interest sale and non-operated property divestiture for combined net proceeds of approximately $170 million, which were used to reduce outstanding borrowings
- Reduced our lease operating expenses by more than $30 million (>10%) compared to our 2019 pro forma[3] levels through effective implementation of our field operating best practices
- Reduced our total cash general and administrative expenses by more than 60% from 2019 pro forma[3] levels
- Completed the expansion of our Delaware recycling facilities, allowing for handling of up to 60,000 barrels per day of produced water volume
- Reduced our flaring volumes by 40%
- Achieved our best year on record for safety, with a total recordable incident rate[4] (TRIR) of just 0.54
- Completed our first six-well pad in the Delaware that sourced more than 95% of fracture stimulation volumes (nearly 100 million gallons) from recycled produced water
- Expanded our electrical substation network, allowing for the removal of over 40 diesel generators, thereby improving reliability and reducing our carbon emissions by approximately 34 metric tons
- Lowered our spill rate[5] by 66% as compared to our 2019 figures
- Lowered our average drilling and completion cost per lateral foot by approximately 35%

[1]Total free cash flow from 2Q-4Q 2020. Adjusted free cash flow defined as Adjusted EBITDA minus the sum of operational capital, capitalized interest, capitalized G&A, and interest expense. Adjusted FCF and Adjusted EBITDA are non-GAAP financial measures; please refer to reconciliation of Non-GAAP financial measures.

[2]Please see appendix for reconciliation of Non-GAAP financial measures.

[3]All references to 2019 pro forma figures assume full-year Callon and Carrizo combined financial.

[4]Defined as incidents per 200,000 man hours, inclusive of contractor performance.

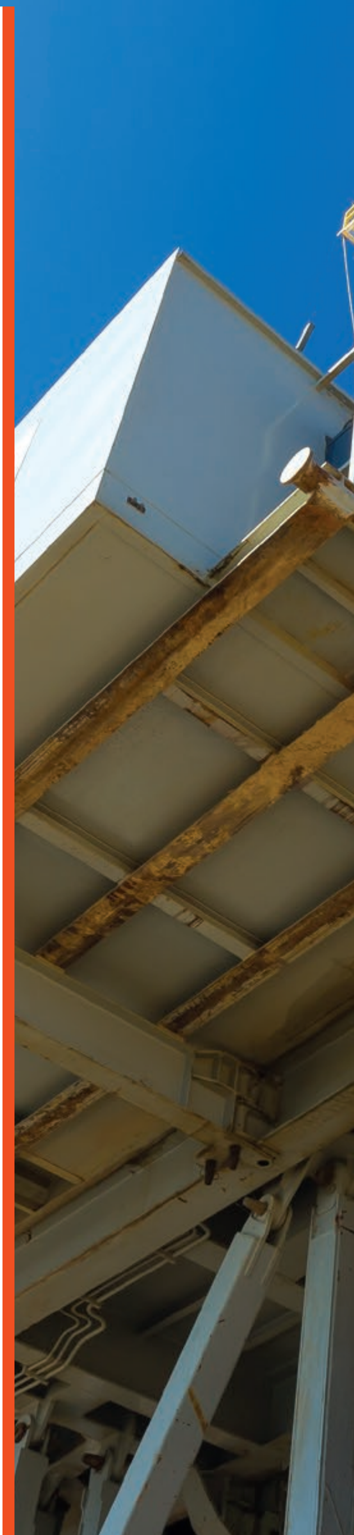
[5]Defined as the volume of oil or water spilled divided by total volume of oil or water produced.

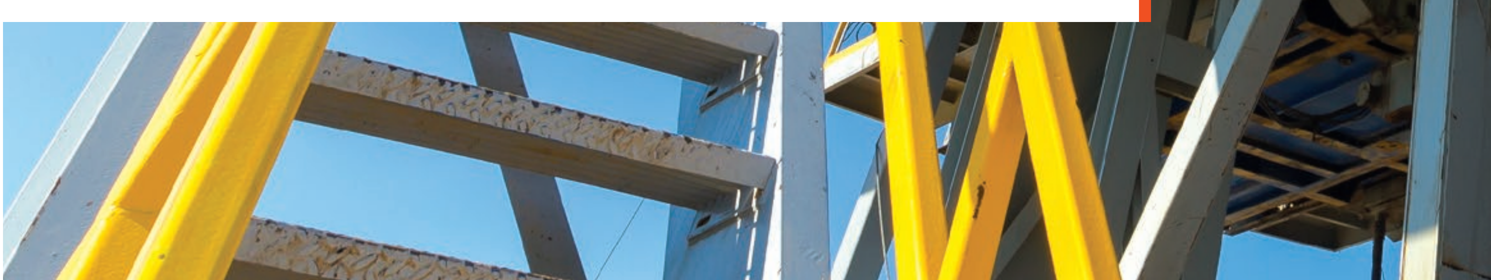
Maximizing value with a focus on cost control and operational efficiency.

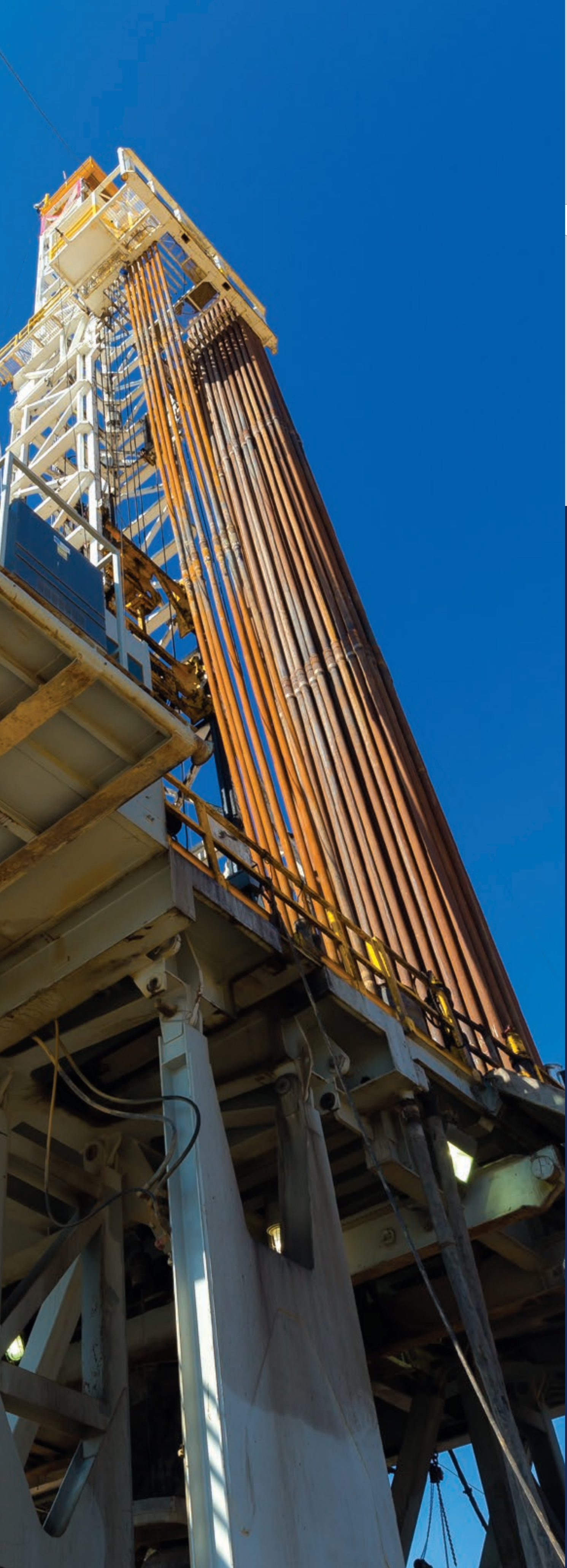
Pivoting quickly after the rapid decline in commodity prices during the first quarter, the entire company came together and did a tremendous job to adjust operations and execute the revised capital program we outlined in April. Over the last three quarters of 2020, we pulled various levers in the field to help drive operating costs down and increase production uptime and reliability, while at the same time reducing our environmental impact and improving as a steward of our natural resources. Our in-house chemist reevaluated our field chemical program requirements, which resulted in lowering costs and improving overall productivity. Field engineers assessed our compression, gas lift, and water management programs to identify opportunities for enhanced reliability, lower costs, and reduced environmental impact. Through these field operation improvements, we achieved dual benefits as we advanced numerous environmental, social, and governance (ESG) initiatives while also lowering our lease operating expenses by roughly $30 million from 2019 pro forma spending levels. These improvements have generated over 10% sustainable savings on our run-rate lease operating costs.

As a company with extensive in-basin experience, we have a strong understanding of the subsurface and depositional environment of the plays in which we operate. This gives us a competitive advantage in identifying, planning, and refining our drilling and completion techniques to deliver further efficiency gains. This past year, even though we set lofty internal well cost savings goals, our teams surpassed our expectations. We were able to lower our average drilling and completion cost per lateral foot by approximately 35% from comparable 2019 costs. The great majority of these savings came from our operational team's ingenuity as they evaluated and optimized drilling and wellbore completion designs, to achieve savings that can be sustained even as commodity prices improve.

Our assets are concentrated in the premier areas of the Permian and Eagle Ford, and we believe we have one of the highest-return portfolios in the industry. With economic thresholds below $45/Bbl including centralized facilities costs, our core inventory can generate very strong economics at current commodity price levels for many years to come. This provides us with a solid opportunity set from which to generate durable cash flows over time. Moreover, we remain steadfast in our long-term value focus by employing our life-of-field development philosophy, guided by a reinvestment rate philosophy that will keep us on a path to sustainable free cash flow growth from repeatable investments in our high-quality asset base. The structural changes we have made and durable nature of our operational efficiencies from scaled development will help us maintain a position of leadership as a low-cost producer in the future.



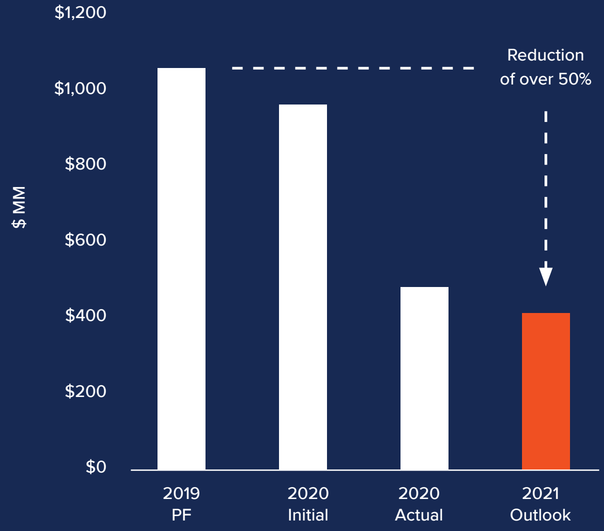




Pushing the boundary on capital efficiency.

Our operations organization has been quick to implement best practices, incorporate subsurface learnings, and drive efficiencies in our capital program. The summation of these efforts has been a significant uplift in our capital efficiency with rapid deployment of our model across all our operating areas. During 2020, we managed to significantly reduce our well costs, in some cases by nearly 40%. While we saw some softening of costs from our vendors, most of our gains have come from improved practices and beneficial well design changes. Our 2021 budgeted well costs are leading edge, and we will continue looking for long-term, sustainable improvements to our cost structure and capital efficiency.

Operational Capital Evolution

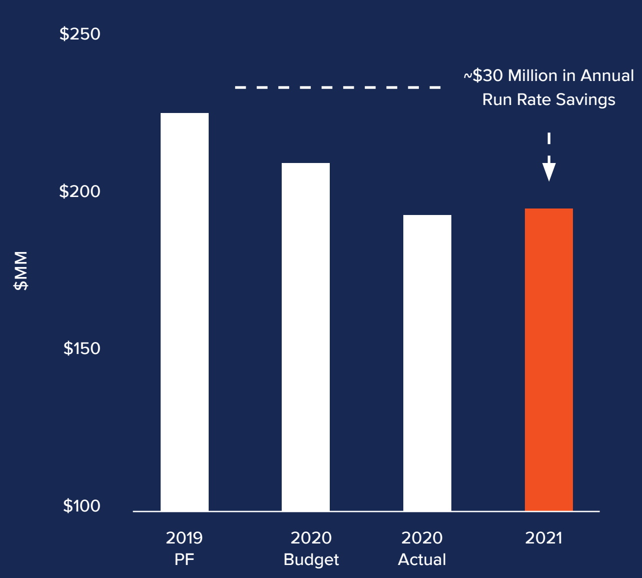


Maximizing value by being leaner and working smarter.

Our team worked hard to identify opportunities for improvement across the expanded asset base in 2020, which helped drive down operational costs. By focusing on proactive maintenance, we were able to reduce the number of required workovers and repairs. We also optimized our chemical treatment, gas lift, compression, and water management programs, which all contributed to lower operating costs.

From a corporate level, we were well positioned for the downturn after taking a deliberate approach to right-sizing our organization following our acquisition of Carrizo in December 2019. We take great pride in having the right team in place to meet the challenges of creating and delivering long-term value for our shareholders. We can now thrive in a much lower commodity price environment than we did a couple of years ago as two separate organizations.

Improving Lease Operating Expenses



Positioned to generate organic free cash flow and long-term, competitive returns.

While having high-quality assets and a strong team are requirements for the creation of long-term shareholder value, an appropriate financial strategy is equally important. Despite the various headwinds, our newly integrated team executed flawlessly on a revamped set of operational and financial initiatives that resulted in meaningful improvement to our liquidity and balance sheet as the year progressed. Our relentless focus on cost savings and capital efficiency improvements ultimately delivered over $120 million of adjusted free cash flow since March 2020, helping us to close out the year with a positive free cash flow position for the calendar year. In addition, during the second half of 2020, we completed a series of capital markets transactions and asset dispositions that helped to reduce our net debt by $350 million. Our strategic decisions and the associated execution of those plans this past year enabled us to deliver on our promises to investors, including meaningful free cash flow generation and improved financial strength.

Our medium-term development plans are squarely focused on consistent, organic free cash flow generation and absolute debt reduction. Given our leading operating margins and low-cost resource base, the magnitude and pace of improvements in financial strength from organic cash flows are highly differentiated in the sector. Our 2021 capital budget, inclusive of capitalized expenses, implies a reinvestment rate of approximately 75% of discretionary cash flow at $50 per barrel WTI price and a free cash flow breakeven price of approximately $40 per barrel. We will continue to manage our future capital reinvestment rate[1] within a targeted range of 65% to 75% under a range of pricing environments, which is expected to generate free cash flow in a range of $500 to $800 million over the next three years, assuming WTI oil prices of $50 to $60 per barrel. In addition, we are targeting asset monetizations of approximately $125 to $225 million in 2021 to further our debt reduction goals.

The oil and gas industry has weathered many downturns and volatile surprises over its long history, but the companies that have thrived were the low-cost leaders with a strong portfolio of assets that could create durable returns. Callon has positioned itself from a development and asset ownership position to meet these requirements. As we further reduce our debt levels and continue employing a thoughtful and sustainable development philosophy, we believe investors will recognize the repeatable and profitable nature of our business model. Our improving capital structure and focus on free cash flow generation should place us in a position to continue broadening the available strategic options for future value creation for investors.

[1]Callon defines "reinvestment rate" as (Accrued Operational Capital Expenditures) / (Adjusted Discretionary Cash Flow - Capitalized Expenses).

Corporate sustainability is critical to our ability to compete in the market.

We continue to make positive strides as the market has focused more intensely on the sustainability practices of public companies. We have undertaken numerous initiatives to reduce our environmental impact and improve as a steward of our natural resources. Equally important is the idea of reinforcing cultural values that drive our continuous improvement on ESG initiatives, not just in the areas of environmental impact, but also our human capital and strategic processes.

During the past year, while many others pulled back to protect their financial position, we maintained — and in some areas, grew — our commitment to ESG. Our operations team continued to refine field practices that reduced our environmental impact with measurable success. In 2020, we reduced flaring volumes by 40% and greenhouse gas (GHG) emissions by over 20% year-over-year. Similarly, spill volumes have been reduced by over 60%, and our produced water recycling program continues to grow. In the Delaware Basin, we completed the expansion of our recycling facilities allowing for handling of up to 60,000 barrels per day of produced water volume. Our use of recycled water volumes for completions reached a new peak when we employed over 95% recycled produced water volumes on a six-well pad in the Delaware, saving nearly 100 million gallons of local water resources. We will continue growing our recycling program and implementing industry-leading practices to further reduce our carbon emissions.

Safety has always been a core value, and the safety of our employees and their families remains at the forefront of our business decisions. When it became clear that the U.S. would not be able to avoid the pandemic's reach, we quickly pivoted to a company-wide remote workforce while still operating a full program before tempering our activity levels. We implemented new safe-work policies both in the office and in the field. Despite the ongoing pandemic, our company marked a new record low for total recordable incidents for the second consecutive year, which exemplifies our safety culture. Our practices are designed not only to protect and foster a culture of safety with our employees, but with our various service providers and suppliers as well.

At Callon, we believe that corporate responsibility starts with governance, which starts with our Board of Directors. Consistent with our focus on integrating sustainable practices into all aspects of our business, in 2020, we restructured our board to assign specific responsibilities for ESG oversight to the Nominating and Environmental, Social & Governance Committee. In addition, our executive compensation practices continue to evolve to better align with the investor priorities for the energy sector. Full details of our governance programs and updated executive compensation metrics can be found in our recently published proxy.

Continued focus on social responsibility for sustainable growth.

During 2020, we pushed forward on several sustainability initiatives despite the challenges of working remotely. For the full year, we realized a 10% improvement in our safety rates, making it another record safety year. Our focus on environmental responsibility also allowed us to achieve a 66% reduction in our spill rate, a 40% reduction in our flared volumes, and a reduction of more than 20% in our greenhouse gas emissions—a monumental achievement considering our production declined only 6%. In addition, we continued testing the use of larger amounts of recycled produced water in our completions with great success. Our last three projects of 2020 utilized nearly 100% recycled produced water.

10%

TRIR Improvement

↓66%

Spill Rate Reduction

↓40%

Reduction in Flared Volumes

↑10%

Recycled Produced Water Usage

>20%

Reduction in GHG Emissions

Gratitude

Throughout the year, we saw our employees bring forth ideas and seize opportunities that contributed to our many operational and financial accomplishments as a company. Equally as important, they spent time finding ways to serve and help their communities as we faced incredible challenges as a nation. Our team stepped up and made contributions in the form of health supplies and protective equipment to local hospitals. Our children, friends, and neighbors created thank you cards for first responders and provided much-needed meals for overworked frontline workers.

Within the company, employees volunteered to test remote working systems and various integration initiatives to ensure a smooth post-merger systems integration. Engineers found improvements to processes and designs which saw positive benefits to the surrounding communities and environments. These actions demonstrate the Callon culture that underpins our company's core values. The willingness of each person to step up when needed and offer a lending hand to fellow team and community members is what makes our organization a special place to work. It is just one of the reasons we've been named a best place to work by the *Houston Chronicle* for four years in a row.

Our industry, as well as our stakeholders, continues to evolve. I am extremely proud of all our employees for remaining focused on our mission and exhibiting the flexibility needed to adapt to the ever-changing rhythm of our industry. It is through their hard work, dedication, and resilience that we are well-positioned for success. And while so much has changed over the past year, one thing remains the same. The path forward for Callon — and the industry as a whole — will continue to be defined by our ability to address the challenges present in a dynamic and challenging economic environment. Our ability to identify evolving market conditions and remain agile will continue to be a differentiating factor. We must continue to be as efficient, thoughtful, and focused on making the most of every dollar. The accomplishments we made this past year have helped expand the various avenues that will help us achieve our goals. Our continued focus on protecting shareholder value and methodically executing on steps that enhance our cash flow and reduce our debt is what will set us apart from our peers.

JOSEPH C. GATTO JR.

President & Chief Executive Officer

FORM 10-K

CALLON PETROLEUM | 2020 ANNUAL REPORT

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

FORM 10-K

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

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ____________ to ____________
Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**64-0844345**
State or Other Jurisdiction of Incorporation or Organization	I.R.S. Employer Identification No.
One Briarlake Plaza 2000 W. Sam Houston Parkway S., Suite 2000 Houston, Texas	**77042**
Address of Principal Executive Offices	Zip Code

281-589-5200
(Registrant's Telephone Number, Including Area Code)

Title of Each Class	Securities registered pursuant to Section 12(b) of the Act:	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	CPE	New York Stock Exchange

Securities registered pursuant to section 12 (g) of the Act: None

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2020 was approximately $443.3 million.

The Registrant had 46,153,710 shares of common stock outstanding as of February 23, 2021.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2020) relating to the 2021 Annual Meeting of Shareholders, which are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- our oil and natural gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future capital and operating costs;
- production decline rates from our wells being greater than expected;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to efficiently integrate recent acquisitions; and
- prospect development and property acquisitions.

We caution you that the forward-looking statements contained in this Annual Report on Form 10-K (this "2020 Annual Report on Form 10-K") are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. We disclose these and other important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" in Item 1A of Part I in this 2020 Annual Report on Form 10-K. These factors include:

- the volatility of oil and natural gas prices or a prolonged period of low oil or natural gas prices;
- general economic conditions, including the availability of credit and access to existing lines of credit;
- changes in the supply of and demand for oil and natural gas, including as a result of the COVID-19 pandemic and various governmental actions taken to mitigate its impact or actions by, or disputes among, members of OPEC and other oil and natural gas producing countries, such as Russia, with respect to production levels or other matters related to the price of oil;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, waste and water disposal infrastructure, and personnel;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the potential impact of future drilling on production from existing wells
- difficulties encountered in delivering oil and natural gas to commercial markets;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- cyberattacks on the Company or on systems and infrastructure used by the oil and natural gas industry;
- weather conditions; and
- risks associated with acquisitions, including the acquisition of Carrizo Oil & Gas, Inc. (the "Carrizo Acquisition" or the "Merger").

Should one or more of these risks or uncertainties occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Additional risks or uncertainties that are not currently known to us, that we currently deem to be immaterial, or that could apply to any company could also materially adversely affect our business, financial condition, or future results. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

In addition, we caution that reserve engineering is a process of estimating oil and natural gas accumulated underground and cannot be measured exactly. Accuracy of reserve estimates depend on a number of factors including data available at the point in time, engineering interpretation of the data, and assumptions used by the reserve engineers as it relates to price and cost estimates and recoverability. New results of drilling, testing, and production history may result in revisions of previous estimates and, if significant, would impact future development plans. As such, reserve estimates may differ from actual results of oil and natural gas quantities ultimately recovered.

Except as required by applicable law, all forward-looking statements attributable to us 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 persons acting on our behalf may issue.

GLOSSARY OF CERTAIN TERMS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their prescribed meanings when used in this report. As used in this document:

- **ARO**: asset retirement obligation.
- **ASU**: accounting standards update.
- **Bbl** or **Bbls**: barrel or barrels of oil or natural gas liquids.
- **Boe**: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of natural gas. The ratio of one barrel of oil or NGLs to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- **Boe/d**: Boe per day.
- **Btu**: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **Completion**: the process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- **Cushing**: an oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- **Development well**: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
- **EPA**: United States Environmental Protection Agency.
- **Exploratory well**: a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.
- **Extension well**: a well drilled to extend the limits of a known reservoir.
- **FASB**: Financial Accounting Standards Board.
- **GAAP**: Generally Accepted Accounting Principles in the United States.
- **GHG**: greenhouse gases.
- **Henry Hub**: a natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- **Horizontal drilling**: a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at an angle within a specified interval.
- **ICE:** Intercontinental Exchange.
- **LIBOR**: London Interbank Offered Rate.
- **LOE**: lease operating expense.
- **MBbls**: thousand barrels of oil.
- **MBoe**: thousand Boe.
- **Mcf**: thousand cubic feet of natural gas.
- **MEH**: Magellan East Houston, a delivery point in Houston, Texas that serves as a benchmark for crude oil.
- **MMBoe**: million Boe.
- **MMBtu**: million Btu.
- **MMcf**: million cubic feet of natural gas.
- **NGL or NGLs**: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- **Non-productive well**: A well that is found to be incapable of producing oil or gas in sufficient quantities to justify completion, or upon completion, the economic operation of an oil or gas well.
- **NYMEX**: New York Mercantile Exchange.
- **Oil**: includes crude oil and condensate.
- **OPEC**: Organization of Petroleum Exporting Countries.
- **PDPs**: proved developed producing reserves.
- **Productive well**: A well that is found to be capable of producing oil or gas in sufficient quantities to justify completion as an oil or gas well.
- **Proved developed producing reserves:** Proved 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.
- **Proved reserves:** Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and
b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- **Proved undeveloped reserves:** Proved 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 specific circumstances justify a longer time. Under no circumstances shall estimates of 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 an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
- **PUDs**: proved undeveloped reserves.
- **PV-10 (Non-GAAP)**: the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies from period to period. This is a non-GAAP measure. See “Items 1 and 2 - Business and Properties - Proved Oil and Gas Reserves - Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)”.
- **Realized price**: the cash market price less all expected quality, transportation and demand adjustments.
- **Royalty interest**: an interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
- **RSU**: restricted stock units.
- **SEC**: United States Securities and Exchange Commission.
- **Waha**: a natural gas delivery point in West Texas that serves as the benchmark for natural gas.
- **Working interest**: an 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.
- **WTI**: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.

ITEMS 1 and 2 – Business and Properties

Overview

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

We are an independent oil and natural gas company focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. Our activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas, as well as the Eagle Ford, which we entered into through our acquisition of Carrizo Oil & Gas, Inc. ("Carrizo") in late 2019. Our primary operations in the Permian reflect a high-return, oil-weighted drilling inventory with multiple prospective horizontal development intervals and are complemented by a well-established and repeatable cash flow generating business in the Eagle Ford.

Major Developments in 2020

COVID-19 Outbreak and Global Industry Downturn. The worldwide outbreak of COVID-19 in 2020, the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19 have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. As a result, there is an excess supply of oil in the United States, which could continue for a sustained period; this is in addition to recent and continued excess supply of natural gas in the United States. This excess supply, in turn, resulted in transportation and storage capacity constraints in the United States during 2020, although these constraints have recently lessened and inventories have declined from peak levels.

The COVID-19 outbreak and its development into a pandemic in March 2020 have required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, suppliers and the communities in which we operate. Our operational employees continue to work on site. However, we have taken various precautionary measures with respect to such operational employees such as requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site, being prepared to quarantine any operational employees who have shown signs of COVID-19 (regardless of whether such employee has been confirmed to be infected), and, while at the work site, imposing safety protocols in accordance with the guidelines released by the Centers for Disease Control and Prevention. In addition, a large portion of our non-operational employees are now working remotely, and we have established COVID-19 specific safety protocols for those working from the office. We have not yet experienced any material operational disruptions (including disruptions from our suppliers and service providers) as a result of the COVID-19 outbreak.

Financing and Liquidity Updates

- As of December 31, 2020, our senior secured revolving credit facility ("Credit Facility") had a borrowing base and elected commitment amount of $1.6 billion and borrowings outstanding of $985.0 million.
- On November 13, 2020, we completed an exchange with certain holders of our 6.25% Senior Notes due 2023 (the "6.25% Senior Notes"), 6.125% Senior Notes due 2024 (the "6.125% Senior Notes"), 8.25% Senior Notes due 2025 (the "8.25% Senior Notes"), and 6.375% Senior Notes due 2026 (the "6.375% Senior Notes" and together with the 6.25% Senior Notes, the 6.125% Senior Notes and 8.25% Senior Notes, the "Senior Unsecured Notes") to exchange $389.0 million of aggregate principal amount of Senior Unsecured Notes for $216.7 million of our 9.00% Second Lien Senior Secured Notes due 2025 (the "November 2020 Second Lien Notes") and warrants for 1.75 million shares of common stock (the "November 2020 Warrants").
- On September 30, 2020, we issued $300.0 million in aggregate principal amount of our 9.00% Second Lien Senior Secured Notes due 2025 ("September 2020 Second Lien Notes" and together with the November 2020 Second Lien Notes the "Second Lien Notes") and warrants for 7.3 million shares of common stock ("September 2020 Warrants") for proceeds, net of issuance costs, of approximately $288.6 million.

See "Note 7 – Borrowings", "Note 8 - Derivative Instruments and Hedging Activities" and "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for further discussion.

Divestitures. On September 30, 2020, we sold an undivided 2.0% (on an 8/8ths basis) overriding royalty interest, proportionately reduced to our net revenue interest, in and to our operated leases, excluding certain interests ("ORRI Transaction"). On November 2, 2020, we also closed on a sale of substantially all of our non-operated assets. We received combined net proceeds of approximately $165.4 million, which was used to repay borrowings outstanding under the Credit Facility.

See “Note 4 – Acquisitions and Divestitures” of the Notes to our Consolidated Financial Statements for further discussion.

Reverse Stock Split. On August 7, 2020 following approval by our shareholders at the June 8, 2020 annual meeting of shareholders of an amendment to our Certificate of Incorporation to effect a reverse stock split, our Board of Directors approved a reverse stock split of our common stock at a ratio of 1-for-10 and a proportionate reduction in the number of authorized shares of our common stock. Our common stock began trading on a split-adjusted basis on August 10, 2020 upon opening of the markets. See “Note 11 – Stockholders' Equity” of the Notes to our Consolidated Financial Statements for further discussion.

Operational Activity. Due to the decline in crude oil prices in 2020 and ongoing uncertainty regarding the oil supply-demand macro environment, we reduced our development plan in order to preserve capital, including the temporary cessation of all drilling and completion activities for most of the second and third quarters of 2020. We reactivated two completion crews, one each in the Eagle Ford and Permian, both of which completed previously drilled multi-well projects during September. Subsequently, one of the two completion crews was released and three drilling rigs resumed operations, two restarting operations in the Permian during September and the third reactivated in the Eagle Ford during October. This reduction in activity resulted in our actual 2020 operational capital expenditures to be approximately 50% of our original operational capital budget for 2020 of $975.0 million.

During the year ended December 31, 2020, we drilled 91 gross (86.0 net) wells and completed 90 gross (81.4 net) wells. Our net daily production was 101,620 Boe/d (approximately 63% oil), an increase of approximately 146% when compared to the year ended December 31, 2019, primarily as a result of the properties acquired in the Carrizo Acquisition in late 2019 as well as our developmental activities during the year. For the year ended December 31, 2020, our estimated proved reserves were 475.9 MMBoe and included proved oil reserves of 289.5 MMBbls (61% of total proved reserves). Approximately 45% of our 2020 year-end estimated proved reserves were classified as proved developed. See “— Summary of 2020 Proved Reserves, Production and Drilling by Region” below for additional details.

Our Business Strategy

Our principal objective is to enhance shareholder value through capital efficient development of our proved reserves, management of our operating costs, and maximization of cash flows while acting as a responsible corporate citizen in the areas in which we operate. Key elements of the execution of this strategy include:

- Improving the capital efficiency of our operations in terms of both well productivity and capital outlays, including supporting facilities;
- Optimizing the development of our multi-zone resource base through thoughtful plans of life of field development that are informed by extensive analysis of subsurface data and empirical well results;
- Maturing our asset base into a sustainable operating model for profitable reinvestment of cash flows for attractive, long-term returns on capital;
- Maintaining strong cash margins per unit of production through cost management and proactive investment in production infrastructure;
- Enhancing our financial position, focusing on appropriate capital allocation decisions under various commodity pricing scenarios, prudent risk management and generating free cash flow to reduce leverage;
- Maximizing and preserving our inventory of well locations through selective delineation of emerging targets on our existing acreage positions and scaled development of proven areas to minimize potential degradation of future drilling locations; and
- Integrating sustainable business practices that minimize our impact on the environment, empower and develop a diverse workforce, and enrich our communities.

Our Strengths

We believe the following attributes position Callon to achieve its objectives:

- **Strong Foundation** - Reputation as a safe and responsible operator built over several decades in the oil and gas industry;
- **Quality Assets** - High quality Permian asset base with several years of proven well results from multiple target zones that benefit from early investments in critical supporting infrastructure including sustainable investments in water recycling and a more mature asset base in the Eagle Ford which has lower operational risk and generates repeatable, profitable well results;
- **Operational Control** - High degree of operational control that allows us to efficiently maximize value through daily and long-term decisions that drive our strategy;
- **Talented Workforce** - Seasoned employee base that has benefited from the addition of employees from the Carrizo Acquisition, who have been integrated into our collaborative culture;

- **Sustainable Business Practices** - Focus on value creation in a responsible manner by utilizing an operating philosophy that provides our employees a safe workplace while at the same time conducting operations in a manner that is environmentally sensitive and community aware. See our Sustainability Report published on our company website (www.callon.com) for performance highlights and additional information. Information contained in our Sustainability Report is not incorporated by reference into, and does not constitute a part of, this 2020 Annual Report on Form 10-K.

Oil and Natural Gas Properties

Summary of 2020 Proved Reserves, Production and Drilling by Region

	Permian	Eagle Ford	Total
Proved reserves			
Crude oil (MBbls)	215,572	73,915	289,487
Natural gas (MMcf)	477,160	64,438	541,598
NGLs (MBbls)	84,369	11,757	96,126
Total proved reserves (MBoe)	379,467	96,412	475,879
Proved reserves by classification (MBoe)			
Proved developed	164,660	47,265	211,925
Proved undeveloped	214,807	49,147	263,954
Total proved reserves (MBoe)	379,467	96,412	475,879
Percent of proved developed reserves	78%	22%	100%
Percent of proved undeveloped reserves	81%	19%	100%
Percent of total reserves	80%	20%	100%

Production volumes	Permian Total	Permian Per Day	Eagle Ford Total	Eagle Ford Per Day	Total	Total Per Day
Crude oil (MBbls and Bbls/d)	14,113	38,560	9,430	25,765	23,543	64,325
Natural gas (MMcf and Mcf/d)	32,087	87,669	8,714	23,809	40,801	111,478
NGLs (MBbls and Bbls/d)	5,390	14,727	1,460	3,989	6,850	18,716
Total production volumes (MBoe and Boe/d)	24,851	67,899	12,342	33,721	37,193	101,620
Percent of total production		67%		33%		100%

	Permian		Eagle Ford		Total	
Operated Well Data	Gross	Net	Gross	Net	Gross	Net
Drilled	52	47.3	39	38.7	91	86.0
Completed	52	46.9	38	34.5	90	81.4
As of December 31, 2020						
Drilled but uncompleted	28	25.3	37	36.8	65	62.1
Producing	846	738.3	650	582.3	1,496	1,320.6

Regional Overview

Permian

As of December 31, 2020, our acreage position comprised 130,349 gross (106,371 net) acres in the Permian, all of which was located in the Midland and Delaware Basins. Average net production from our Permian properties increased approximately 69% to 67,899 Boe/d in 2020 from 40,287 Boe/d in 2019, primarily as a result of the Carrizo Acquisition. We currently expect to direct the majority of our 2021 Capital Budget, as defined below, towards opportunities in the Permian.

Eagle Ford

We acquired our Eagle Ford properties, primarily located in LaSalle County and, to a lesser extent, in McMullen, Frio and Atascosa counties in Texas, through the Carrizo Acquisition in late 2019. As of December 31, 2020, we held interests in approximately 90,079 gross (73,683 net) acres. Average net production from our Eagle Ford properties was 33,721 Boe/d in 2020.

Proved Oil and Gas Reserves

The following table sets forth summary information with respect to our estimated proved reserves, standardized measure of discounted future net cash flows and PV-10 for the years ended December 31, 2020, 2019, and 2018. For each year in the table below, the estimated proved reserves were prepared by DeGolyer and MacNaughton ("D&M"), Callon's independent third party reserve engineers, with the exception of the estimated proved reserves in 2019 obtained as a result of the Carrizo Acquisition in late 2019, which were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), the independent third party reserve engineers historically retained by Carrizo. For further information concerning D&M's estimates of our proved reserves as of December 31, 2020, see the reserve report included as an exhibit to this 2020 Annual Report on Form 10-K. The prices used in the calculation of our estimated proved reserves and PV-10 were based on the average realized prices for sales of oil, NGLs, and natural gas on the first calendar day of each month during the year ("12-Month Average Realized Price") in accordance with SEC rules.

	As of December 31,		
	2020	**2019**	**2018**
Proved developed reserves [1][2]			
Crude oil (MBbls)	128,923	152,687	92,202
Natural gas (MMcf)	238,119	320,676	218,417
NGLs (MBbls)	43,315	24,844	—
Total proved developed reserves (MBoe)	211,925	230,977	128,605
Proved undeveloped reserves [1][2]			
Crude oil (MBbls)	160,564	193,674	87,895
Natural gas (MMcf)	303,479	436,458	132,049
NGLs (MBbls)	52,811	42,618	—
Total proved undeveloped reserves (MBoe)	263,954	309,035	109,903
Total proved reserves [1][2]			
Crude oil (MBbls)	289,487	346,361	180,097
Natural gas (MMcf)	541,598	757,134	350,466
NGLs (MBbls)	96,126	67,462	—
Total proved reserves (MBoe)	475,879	540,012	238,508
Proved developed reserves %	45%	43%	54%
Proved undeveloped reserves %	55%	57%	46%
12-Month Average Realized Prices			
Crude oil ($/Bbl)	$37.44	$53.90	$58.40
Natural gas ($/Mcf)	$1.02	$1.55	$3.64
NGLs ($/Bbl)	$11.10	$15.58	$—
Standardized measure of discounted future net cash flows (GAAP) (in millions)	$2,310.4	$4,951.0	$2,941.3
PV-10 (Non-GAAP) (in millions):			
Proved developed PV-10	$1,577.3	$3,246.8	$2,222.0
Proved undeveloped PV-10	767.7	2,122.8	927.2
Total PV-10 (Non-GAAP)	$2,345.0	$5,369.6	$3,149.2

(1) Effective January 1, 2020, certain of our natural gas processing agreements were modified to allow us to take title to NGLs resulting from the processing of our natural gas. As a result, reserve volumes for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, we presented our reserve volumes for NGLs with natural gas.

(2) Includes the proved reserves associated with the Carrizo Acquisition for the years ended December 31, 2020 and 2019.

Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)

We believe that the presentation of PV-10 provides greater comparability when evaluating oil and gas companies due to the many factors unique to each individual company that impact the amount and timing of future income taxes. In addition, we believe that PV-10 is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and gas companies. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP. The definition of PV-10 as defined in "Glossary of Certain Terms" may differ significantly from the definitions used by other companies to compute similar measures. As a result, PV-10 as defined may not be comparable to similar measures provided by other companies. A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented below. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

	As of December 31,		
	2020	2019	2018
		(In millions)	
Standardized measure of discounted future net cash flows (GAAP)	$2,310.4	$4,951.0	$2,941.3
Add: present value of future income taxes discounted at 10% per annum	34.6	418.6	207.9
PV-10 (Non-GAAP)	$2,345.0	$5,369.6	$3,149.2

Proved Reserves

Our reserve estimates are conducted from fundamental petrophysical, geological, engineering, financial and accounting data. Reserves are estimated based on production decline analysis, analogy to producing offsets, detailed reservoir modeling, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations and using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. To establish reasonable certainty of our proved reserves estimates, including material additions to our proved reserves, we use certain technologies and economic data, including production and well test data, historical well costs and operating data, geologic and seismic data, and subsurface information obtained through wellbores such as electrical logs, radioactive logs, reservoir core samples, fluid samples, and static and dynamic pressure information. Non-producing reserves are estimated by analogy to producing offsets, with consideration given to a development plan approved by Callon's management.

As of December 31, 2020, our estimated proved reserves totaled 475.9 MMBoe, a decrease of 12% from the prior year end, and included 289.5 MMBbls of oil, 541.6 Bcf of natural gas and 96.1 MMBbls of NGLs with a standardized measure of discounted future net cash flows of $2.3 billion. Oil constituted approximately 61% of our total estimated proved reserves as well as our total estimated proved developed reserves. The following table provides a summary of the changes in our proved reserves for the year ended December 31, 2020.

	Total (MBoe)
Proved reserves as of December 31, 2019	540,012
Extensions and discoveries	41,407
Revisions to previous estimates	(52,227)
Sales of reserves in place	(16,120)
Production	(37,193)
Proved reserves as of December 31, 2020	475,879

Further details of the changes in our proved reserves for the year ended December 31, 2020 are as follows:

- *Extensions and discoveries.* We added 41.4 MMBoe of new reserves in extensions and discoveries through our development efforts in our operating areas. See the table below for the impact of extensions and discoveries on total proved and proved undeveloped reserves for 2020:

Extensions and discoveries	Total (MBoe)
Total proved	41,407
Proved undeveloped	29,698
Difference (Proved developed producing)[1]	11,709

(1) These extensions and discoveries were not recognized as proved undeveloped reserves in a prior period, but rather were recognized directly as proved developed producing reserves as there was not an offset proved developed producing location at the time of drilling in order to classify as a proved undeveloped location.

We incurred costs of $77.5 million for the extensions and discoveries associated with proved developed producing wells during 2020.

- *Revisions to previous estimates.* The table below shows the components of the net negative revisions of previous estimates of 52.2 MMBoe.

	Total (MBoe)
Pricing[1]	(26,254)
Performance[2]	(24,210)
PUDs removed due to changes in development plan[3]	(23,923)
NGL yield[4]	14,658
Assumptions for operational expenses[5]	7,502
Total revisions to previous estimates	(52,227)

(1) Primarily as a result of the change in 12-Month Average Realized Price of crude oil, which decreased by approximately 31% as compared to December 31, 2019. Included in the decrease in the table above was 2.1 MMBoe associated with proved developed producing wells and 0.8 MMBoe associated with proved undeveloped wells that were no longer economic at December 31, 2020 as a result of the decrease in the 12-Month Average Realized Price of crude oil.

(2) Primarily related to reductions in anticipated hydrocarbon recoveries resulting from observed well performance over longer production timeframes during the testing of various full field development plan concepts.

(3) Removed primarily as a result of changes in anticipated well densities as we develop our properties in an effort to increase capital efficiency and cash flow generation.

(4) Volumetric impact from presenting NGLs and natural gas separately due to the modification of certain of our natural gas processing agreements which allow us to take title to NGLs resulting from the processing of our natural gas subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, we presented our reserve volumes for NGLs with natural gas.

(5) Reduced assumptions for operational expenses as we continued to improve our field practices during the integration of the properties acquired from Carrizo.

- *Sales of reserves in place.* The 16.1 MMBoe of sales of reserves in place were primarily associated with the ORRI Transaction and the sale of substantially all of our non-operated assets. See “Note 4 - Acquisitions and Divestitures” of the Notes to our Consolidated Financial Statements for further discussion.

Proved Undeveloped Reserves

Annually, we review our PUDs to ensure appropriate plans exist for development of this reserve category. PUD reserves are recorded only if we have plans to convert these reserves into PDPs within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2021 Capital Budget, as defined below, and, in subsequent years, the allocation of capital within our long-range business plan to convert PUDs to PDPs within this five-year period. The following table provides a summary of the changes in our PUDs for the year ended December 31, 2020.

	Total (MBoe)
PUDs as of December 31, 2019	309,036
Extensions and discoveries	29,698
Revisions to previous estimates	(27,220)
Sales of reserves in place	(6,158)
Converted to proved developed	(41,402)
PUDs as of December 31, 2020	263,954

- *Extensions and discoveries.* We added 29.7 MMBoe of new reserves in extensions and discoveries as a result of additional offset locations associated with our drilling program.

- *Revisions to previous estimates.* The table below shows the components of the net negative revisions of previous estimates of 27.2 MMBoe.

	Total (MBoe)
PUDs removed due to changes in development plan(1)	(23,923)
Pricing(2)	(7,101)
NGL yield(3)	4,648
Performance(4)	(4,280)
Assumptions for operational expenses(5)	3,436
Total revisions to previous estimates	(27,220)

(1) Removed primarily as a result of changes in anticipated well densities as we develop our properties in an effort to increase capital efficiency and cash flow generation.
(2) Primarily as a result of the change in 12-Month Average Realized Price of crude oil which decreased by approximately 31% as compared to December 31, 2019. Included in the decrease in the table above was 0.8 MMBoe associated with proved undeveloped wells that were no longer economic at December 31, 2020.
(3) Volumetric impact from presenting NGLs and natural gas separately due to the modification of certain of our natural gas processing agreements which allow us to take title to NGLs resulting from the processing of our natural gas subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, we presented our reserve volumes for NGLs with natural gas.
(4) Primarily related to reductions in anticipated hydrocarbon recoveries resulting from observed well performance over longer production timeframes during the testing of various full field development plan concepts.
(5) Reduced assumptions for operational expenses as we continued to improve our field practices during the integration of the properties acquired from Carrizo.

- *Sales of reserves in place.* The 6.2 MMBoe of sales of reserves in place were primarily associated with the ORRI Transaction. See “Note 4 - Acquisitions and Divestitures” of the Notes to our Consolidated Financial Statements for further discussion.

- *Converted to proved developed.* During 2020, we converted 41.4 MMBoe of PUDs that were booked as PUDs as of December 31, 2019 to proved developed at a cost of $224.4 million, or $5.42 per Boe. During 2020, our PUD conversion was below 20% primarily as a result of the significant decrease in operational capital expenditures, which included the temporary cessation of all drilling and completion activities for most of the second and third quarters of 2020, due to declines in crude oil prices in 2020 and ongoing uncertainty regarding the oil supply-demand macro-economic environment. We currently estimate that we will convert between 40% and 45% of our PUDs as of December 31, 2020 in 2021 and 2022.

During 2020, we also incurred $76.4 million on PUDs that were drilled but uncompleted as of December 31, 2020. As of December 31, 2020, we had 25.3 MMBoe of PUDs associated with drilled but uncompleted wells. All of the reserves associated with drilled but uncompleted wells are scheduled to be completed in 2021. We expect to incur approximately $126.0 million of capital expenditures to complete these wells.

At December 31, 2020, we did not have any reserves that have remained undeveloped for five or more years since the date of their initial booking and all PUD locations are scheduled to be developed within five years of their initial booking.

Qualifications of Technical Persons

In accordance with the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers, D&M prepared 100% of our estimates of proved reserves as of December 31, 2020 and 2018 and 40% of our proved reserves as of December 31, 2019. Ryder Scott prepared the estimates of proved reserves associated with the Carrizo Acquisition, which comprised approximately 60% of our proved reserves as of December 31, 2019. D&M is a respected company in the reservoir engineering field and provides petroleum property analysis for other upstream companies. The technical persons responsible for preparing the reserves estimates meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Neither D&M nor Ryder Scott owns an interest in our properties, and neither is employed on a contingent fee basis.

Our internal director of reserves has over 20 years of experience in the petroleum industry and extensive experience in the estimation of reserves and the review of reserve reports prepared by third party engineering firms. Compliance as it relates to reporting the Company’s reserves is the responsibility of our Chief Operating Officer, who is also our principal engineer. He has over 30 years of operations and industry experience and holds B.S. and Ph.D. degrees in Petroleum Engineering, in addition to a M.S. in Environmental and Planning Engineering, and is experienced in asset evaluation and management.

Internal Controls Over Reserve Estimation Process

The primary inputs to the reserve estimation process are comprised of technical information, financial data, production data, and ownership interest. All field and reservoir technical information is assessed for validity when the internal reserve engineer holds technical meetings with our geoscientists, operations, and land personnel to discuss field performance and to validate future development plans. The other inputs used in the reserve estimation process, including, but not limited to, future capital expenditures, commodity price differentials, production costs, and ownership percentages are subject to internal controls over financial reporting and are assessed for effectiveness annually.

To further enhance the control environment over the reserve estimation process, our Strategic Planning and Reserves Committee, an independent committee of the Company's board of directors (the "Board of Directors"), assists management and the Board of Directors with its oversight of the integrity of the determination of our oil and natural gas reserves and the work of the independent third party reserve engineers. The Strategic Planning and Reserves Committee's charter also specifies that it shall perform, in consultation with the Company's management and senior reserves and reservoir engineering personnel, the following responsibilities:

- Oversee the appointment, qualification, independence, compensation and retention of the independent third party reserve engineers engaged by the Company (including resolution of material disagreements between management and the independent third party reserve engineers regarding reserve determination) for the purpose of preparing or issuing an annual reserve report. The Strategic Planning and Reserves Committee shall review any proposed changes in the appointment of the independent third party reserve engineers, determine the reasons for such proposal, and whether there have been any disputes between the independent third party reserve engineers and management.
- Review the Company's significant reserves engineering principles and any material changes thereto, and any proposed changes in reserves engineering standards and principles which have, or may have, a material impact on the Company's reserves disclosure.
- Review with management and the independent third party reserve engineers the proved reserves of the Company, and, if appropriate, the probable reserves, possible reserves and the total reserves of the Company, including: (i) reviewing significant changes from prior period reports; (ii) reviewing key assumptions used or relied upon by the independent third party reserve engineers; (iii) evaluating the quality of the reserve estimates prepared by the independent third party reserve engineers and the Company relative to the Company's peers in the industry; and (iv) reviewing any material reserves adjustments and significant differences between the Company's and independent third party reserve engineers' estimates.
- If the Strategic Planning and Reserves Committee deems it necessary, it shall meet in executive session with the independent third party reserve engineers to discuss the oil and gas reserve determination process and related public disclosures, and any other matters of concern in respect of the evaluation of the reserves.

During our last fiscal year, we filed no reports with other federal agencies which contain an estimate of proved reserves.

See "Item 8. Financial Statements and Supplementary Data - Supplemental Information on Oil and Natural Gas Operations" for additional information regarding our estimated proved reserves and the present value of estimated future net revenues from these proved reserves.

Capital Budget

Our Board approved an operational capital budget for expenditures of up to $430.0 million (the "2021 Capital Budget"), with approximately 80% directed towards drilling, completion, and equipment expenditures. Our scaled development plan for 2021 will continue to employ our life of field development philosophy and benefit from our balanced capital deployment strategy. The 2021 Capital Budget leverages the structural savings and operational efficiencies achieved during 2020 from shared best practices following the integration of Callon and Carrizo. Approximately 70% of the 2021 Capital Budget is allocated towards development in the Permian with the remaining 30% towards development in the Eagle Ford. As part of our 2021 operated horizontal drilling program, we expect to drill approximately 55 to 65 gross operated wells and complete approximately 90 to 100 gross operated wells.

Our revenues, earnings, and liquidity are substantially dependent on the prices we receive for, and our ability to develop, our reserves of oil and natural gas. We believe that we are positioned to execute on our strategy even during downturns in the industry due to our resource base, low cost structure, risk management, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

Drilling Activity

The following table sets forth our operated and non-operated drilling activity for the years ended December 31, 2020, 2019, and 2018. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest therein. As defined by the SEC, the number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. For definitions of exploratory wells, extension wells, development wells, productive wells, and non-productive wells, see "—Glossary of Certain Terms".

	Years Ended December 31,					
	2020		2019 (1)		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells - Productive (2)	22	16.0	56	36.7	55	44.7
Exploratory Wells - Non-productive	—	—	—	—	—	—
Development Wells - Productive	73	66.0	15	11.6	15	12.8
Development Wells - Non-productive	—	—	—	—	—	—

(1) Includes activity on properties acquired in the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) These wells are extension wells. While these wells were drilled on undeveloped acreage targeting formations which in prior periods were not recognized as proved undeveloped due to inadequate evidence using reliable technology to provide reasonably certain results with consistency and repeatability, there were no new field or new reservoir discoveries pursuant to the definition of an exploratory well.

Productive Wells

The following table sets forth the number of productive crude oil and natural gas wells in which we owned an interest as of December 31, 2020.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Permian - Operated	763	665.5	116	101.2	879	766.7
Permian - Non-operated (1)	5	0.9	15	0.7	20	1.6
Total Permian	768	666.4	131	101.9	899	768.3
Eagle Ford - Operated	647	579.8	3	2.5	650	582.3
Eagle Ford - Non-operated (1)	13	0.8	—	—	13	0.8
Total Eagle Ford	660	580.6	3	2.5	663	583.1
Total	1,428	1,247.0	134	104.4	1,562	1,351.4

(1) On November 2, 2020, we sold substantially all of our non-operated assets for net proceeds of $29.6 million, subject to post-closing adjustments.

Production Volumes, Average Sales Prices and Operating Costs

The following tables set forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, our sales of oil and natural gas for the periods indicated.

	Years Ended December 31,		
	2020	**2019** [1]	**2018**
Total production [2]			
Oil (MBbls)			
Permian	14,113	11,365	9,443
Eagle Ford	9,430	300	—
Total oil (MBbls)	23,543	11,665	9,443
Natural gas (MMcf)			
Permian	32,087	19,484	15,477
Eagle Ford	8,714	234	—
Total natural gas (MMcf)	40,801	19,718	15,447
NGLs (MBbls)			
Permian	5,390	93	—
Eagle Ford	1,460	42	—
Total NGLs (MBbls)	6,850	135	—
Total production (MBoe)			
Permian	24,851	14,705	12,018
Eagle Ford	12,342	381	—
Total barrels of oil equivalent (MBoe)	37,193	15,086	12,018
Daily production volumes by product [2]			
Oil (Bbls/d)			
Permian	38,560	31,136	25,871
Eagle Ford	25,765	821	—
Total oil (Bbls/d)	64,325	31,957	25,871
Natural gas (Mcf/d)			
Permian	87,669	53,381	42,321
Eagle Ford	23,809	640	—
Total natural gas (Mcf/d)	111,478	54,021	42,321
NGLs (Bbls/d)			
Permian	14,727	254	—
Eagle Ford	3,989	116	—
Total NGLs (Bbls/d)	18,716	370	—
Total production (Boe/d)			
Permian	67,899	40,287	32,926
Eagle Ford	33,721	1,044	—
Total barrels of oil equivalent (Boe/d)	101,620	41,331	32,926

	Years Ended December 31,		
	2020	2019 [1]	2018
Revenues (in thousands) [2]			
Oil			
Permian	$525,412	$615,235	$530,898
Eagle Ford	325,255	17,872	—
Total oil	850,667	633,107	530,898
Natural gas			
Permian	33,815	35,818	56,726
Eagle Ford	18,051	572	—
Total natural gas	51,866	36,390	56,726
NGLs			
Permian	64,201	1,542	—
Eagle Ford	17,094	533	—
Total NGLs	81,295	2,075	—
Total revenues			
Permian	623,428	652,595	587,624
Eagle Ford	360,400	18,977	—
Total revenues	$983,828	$671,572	$587,624
Operating costs (in thousands)			
Lease operating expense			
Permian	$117,017	$88,636	$69,180
Eagle Ford	77,084	3,191	—
Total lease operating expense	194,101	91,827	69,180
Production and ad valorem taxes			
Permian	39,584	41,777	35,755
Eagle Ford	23,054	874	—
Total production and ad valorem taxes	62,638	42,651	35,755
Gathering, transportation and processing			
Permian	56,856	—	—
Eagle Ford	20,453	—	—
Total gathering, transportation and processing	77,309	—	—
Total operating costs			
Permian	213,457	130,413	104,935
Eagle Ford	120,591	4,065	—
Total operating costs	$334,048	$134,478	$104,935

	Years Ended December 31,		
	2020	2019 [(1)]	2018
Average realized sales price [(2)] (excluding impact of settled derivatives)			
Oil (per Bbl)			
Permian	$37.23	$54.13	$56.22
Eagle Ford	34.49	59.57	—
Total oil (per Bbl)	36.13	54.27	56.22
Natural gas (per Mcf)			
Permian	1.05	1.84	3.67
Eagle Ford	2.07	2.44	—
Total natural gas (per Mcf)	1.27	1.85	3.67
NGL (per Bbl)			
Permian	11.91	16.58	—
Eagle Ford	11.71	12.69	—
Total NGL (per Bbl)	11.87	15.37	—
Total average realized sales price (per Boe)			
Permian	25.09	44.38	48.90
Eagle Ford	29.20	49.81	—
Total average realized sales price (per Boe)	$26.45	$44.52	$48.90
Average realized sales price [(2)] (including impact of settled derivatives)			
Oil (per Bbl)	$40.19	$53.31	$53.31
Natural gas (per Mcf)	1.28	2.22	3.69
NGL (per Bbl)	11.87	15.37	—
Total average realized sales price (per Boe)	$29.03	$44.27	$46.63
Operating costs per Boe			
Lease operating expense			
Permian	$4.71	$6.03	$5.76
Eagle Ford	6.25	8.38	—
Total lease operating expense	5.22	6.09	5.76
Production and ad valorem taxes			
Permian	1.59	2.84	2.98
Eagle Ford	1.87	2.29	—
Total production and ad valorem taxes	1.68	2.83	2.98
Gathering, transportation and processing			
Permian	2.29	—	—
Eagle Ford	1.66	—	—
Total gathering, transportation and processing	2.08	—	—
Total operating costs			
Permian	8.59	8.87	8.74
Eagle Ford	9.77	10.67	—
Total operating costs (per Boe)	$8.98	$8.92	$8.74

(1) Includes activity on properties acquired in the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) Effective January 1, 2020, certain of our natural gas processing agreements were modified to allow us to take title to NGLs resulting from the processing of our natural gas. As a result, sales volumes, prices, and revenues for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for sales volumes, prices, and revenues specifically associated with Carrizo, we presented our sales volumes, prices, and revenues for NGLs with natural gas.

Major Customers

Our production is sold generally on month-to-month contracts at prevailing market prices. The following table presents customers that represented 10% or more of our total revenues for at least one of the periods presented:

	Years Ended December 31,		
	2020	2019	2018
Shell Trading Company	31%	10%	*
Valero Energy	23%	*	*
Rio Energy International, Inc.	*	26%	28%
Enterprise Crude Oil, LLC	*	19%	14%
Plains Marketing, L.P.	*	15%	21%

* - Less than 10% for the respective years.

Because alternative purchasers of oil and natural gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to sell future oil and natural gas production. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security.

Leasehold Acreage

The following table shows our approximate developed and undeveloped leasehold acreage as of December 31, 2020. Developed acreage refers to acreage on which wells have been completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total Acreage		Net Undeveloped Acreage Expiring		
	Gross	Net	Gross	Net	Gross	Net	2021	2022	2023
Permian (1)	121,099	100,645	9,250	5,726	130,349	106,371	1,839	1,510	83
Eagle Ford (2)	77,830	65,311	12,249	8,372	90,079	73,683	47	300	8
Other (3)	2,080	122	75,993	57,070	78,073	57,192	1,234	48,504	6,393
Total	201,009	166,078	97,492	71,168	298,501	237,246	3,120	50,314	6,484

(1) Based on our current plans, approximately 56%, 2% and 24% of the acreage expiring in 2021, 2022 and 2023, respectively, will be developed prior to expiration or extended by lease extension payments.

(2) Based on our current plans, approximately 100% of the acreage expiring in 2021, 2022 and 2023 will be developed prior to expiration or extended by lease extension payments.

(3) Consists of non-core acreage principally located in Texas. We have no current development plans and no proved undeveloped reserves associated with this acreage as of December 31, 2020.

Our lease agreements generally terminate if producing wells have not been drilled on the acreage within their primary term or an extension thereof (a period that is generally from three to five years depending on the area). The percentage of net undeveloped acreage expiring in 2021, 2022 and 2023 assumes that no producing wells have been drilled on acreage within their primary term or have been extended. We manage our lease expirations to ensure that we do not experience unintended material loss of acreage or depths. Our leasehold management efforts include scheduling drilling in order to hold leases by production or timely exercising our contractual rights to extend the terms of leases by continuous operations or the payment of lease extension payments and delay rentals. We may choose to allow some leases to expire that are no longer part of our development plans.

The proved undeveloped reserves associated with acreage expiring over the next three years are not material to the Company.

Human Capital

Callon employs a talented workforce that is integral to our success, and we are committed to the safety, health, and development of each team member. The Callon culture is defined by our values of responsibility, integrity, drive, respect and excellence. These core values are a reflection of our ideals as individuals and direct our actions as a company.

Callon's key human capital management objectives are to attract, retain and develop talent to deliver on our strategy. Due to the technical nature of our business, our success depends on a highly skilled workforce in multiple disciplines including engineering, geology, operations, land, information technology and various other corporate functions. To support the attraction and retention of top talent, our human resources programs are designed to keep our employees safe and healthy, engage employees with an inclusive workplace, reward and support employees through competitive pay and benefit programs, and develop talent to prepare them for critical roles and leadership positions. During 2020, our human capital priorities were focused on the post-merger integration of the Callon and Carrizo workforces and the health and safety of our employees as we adapted to the challenges of COVID-19.

As of December 31, 2020, Callon had 303 permanent, full-time employees. None of our employees are currently represented by a union, and we believe that we have good relations with our employees.

We focus on the following in supporting our human capital:

- **Inclusion and Diversity** - We believe that diversity of backgrounds and perspectives contributes to an innovative workforce and an enriching environment for our employees. Callon is firmly committed to fostering an inclusive, respectful environment and providing equal opportunity to all qualified persons in our hiring, development, and compensation practices. As of December 31, 2020, approximately 36% of our permanent, full-time employees represented minorities and 18% were female.
- **Health and Safety** - Protecting our employees, contractors and communities is a core value at Callon and our top priority. Our Operations Management System ("OMS") establishes clear expectations for operating safely and responsibly throughout the lifecycle of our business. We identify and mitigate safety risks and integrate a culture of safety by operating according to OMS standards, processes, and procedures. Additionally, we share our Safety and Environmental Policy with all employees and contractors which includes each individual's authorization and responsibility to stop work on any activity without the threat or fear of job reprisal. To reinforce accountability for safety results, our Board of Directors included safety performance as a factor in our 2020 annual bonus program. Importantly, during the COVID-19 pandemic, our continuing focus on health and safety enabled us to preserve business continuity without sacrificing our commitment to keeping our employees and their families safe.
- **Employee Compensation, Benefits and Wellness** - Our compensation and benefits programs provide a package designed to attract, retain and motivate employees. In addition to competitive base salaries, we provide a variety of short-term and long-term incentive compensation programs to reward performance relative to key financial and ESG metrics. Callon invests in the health and well-being of our employees and their families by paying 100% of the premiums for our health care plan, which includes telemedicine and an Employee Assistance Program. We also offer comprehensive benefit options including retirement savings plans, life and disability insurance, health savings accounts, flexible spending accounts, and a charitable matching program.
- **Employee Development -** We believe that a key element in our future success, as well as the retention of our employees, is our investment in the development of our team members. Callon fosters an entrepreneurial workplace where employees can expand their skill sets and experience by direct engagement and collaboration with leaders at all levels. Additionally, we offer in-house training programs across our workforce and also invest in our emerging leaders by sponsoring them for prominent leadership development programs. Our development programs also focus on goal setting and feedback to support all of our employees in reaching their personal goals.

For additional information, please see our Sustainability Report published on our company website (www.callon.com). Information contained in our Sustainability Report is not incorporated by reference into, and does not constitute a part of, this 2020 Annual Report on Form 10-K.

Other

Industry Segment and Geographic Information

For segment reporting purposes, the Company considers all of the current development and operating areas to be one reportable segment: the development and production of oil and natural gas. All of the Company's assets are located within the United States and all operations are located within Texas. All of the production revenues generated from operations are contracted and sold to customers located in the United States.

Title to Properties

The Company believes that the title to its oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Nevertheless, we can be involved in title disputes from time to time which may result in litigation. The Company's properties are potentially subject to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements; farm-out agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under various agreements and as a result of unleased minerals or non-participating owners;

- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders, production allocation agreements; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect the Company's rights to production revenues, these characteristics have been taken into account in calculating Callon's net revenue interests and in estimating the size and value of its estimated proved reserves. The Company believes that the burdens and obligations affecting our properties are typical within the industry for properties of the kind owned by Callon.

Seasonality of Business

Weather conditions and seasonality affect the demand for and prices of, oil and natural gas. Due to these fluctuations, results of operations for quarterly interim periods may not be indicative of the results realized on an annual basis.

Competition

The Company operates in the oil and natural gas industry, which is highly competitive. The Company's business experiences strong competition from a number of parties that may range from small independent producers to major integrated companies. Competition affects the Company's ability to acquire additional properties and resources necessary to develop assets. In higher commodity pricing environments, competition also exists in the form of contracting for drilling, pumping, and workover equipment, and securing skilled personnel to both develop and operate existing assets. Many of the competitors mentioned above may be able to pay for more sought-after properties or access equipment, infrastructure, or personnel. The industry also experiences, from time to time, shortages in resources such as the availability of drilling and workover rigs, other equipment, pipes and materials, infrastructures, and skilled personnel, all of which can delay development, exploration, and workover activities as well as result in significant cost increases.

Insurance

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. While not all inclusive, the Company's insurance policies generally protect against bodily injury and property damage, pollution and other environmental damages, employee benefits, employee injury and control of well insurance for its exploration and production operations.

The Company enters into master service agreements with its third-party contractors, including hydraulic fracturing contractors, in which they agree to indemnify the Company for injuries and deaths of the service provider's employees, as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by employees of the Company and the Company's other contractors. Additionally, each party generally is responsible for damage to its own property. The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. While based on the Company's risk analysis we believe that we are properly insured, no assurance can be given that the Company will be able to maintain insurance in the future at rates that it considers reasonable. In such circumstances, the Company may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Corporate Offices

The Company's headquarters are located in Houston, Texas, in a building with office space leased by the Company. We own office buildings in Dilley and Pecos, Texas and lease and own offices in the Midland, Texas area. Because alternative locations to our leased spaces are readily available, the replacement of any of our leased offices would not result in material expenditures**.**

Regulations

General. Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision. Some of these requirements carry substantial penalties for failure to comply.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the method of drilling and completing and operating wells;
- the rate and method of production;
- the surface use and restoration of properties upon which wells are drilled and other exploration activities;
- notice to surface owners and other third parties;

- the venting or flaring of natural gas;
- the plugging and abandoning of wells;
- the discharge of contaminants into water and the emission of contaminants into air;
- the disposal of fluids used or other wastes obtained in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity. To the extent it may be necessary for new interstate natural gas pipelines to be built, there may be a more stringent regulatory approach at the Federal Energy Regulatory Commission ("FERC"), which could impact our ability to obtain new interstate pipeline transportation capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, federal administrative agencies such as FERC, various state and administrative agencies and legislatures, and the courts. Historically, the industry has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and state administrative agencies and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Matters and Regulation. Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations which often require difficult and costly compliance measures. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relating to our owned or operated facilities. Violations of environmental laws could result in administrative, civil or criminal fines and injunctive relief. The strict and joint and several liability nature of certain such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons, air emissions or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. In recent years, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. Although such laws and regulations can increase the cost of planning, designing, installing and operating our facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon our operations, capital expenditures, earnings or competitive position in the marketplace.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA and its state analogs, it is possible that some wastes we generate presently or in the future may be subject to regulation under RCRA and state analogs. Additionally, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Additionally, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA was required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations was not necessary. On April 23, 2019, the EPA determined that a revision of the regulations was not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations in the future, any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of wastes associated with oil and natural gas exploration and production could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or potentially responsible parties ("PRPs") include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating, waste disposal, and water disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination or groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act ("OPA"), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States (a term broadly defined to include, among other things, certain wetlands), as well as state waters for analogous state programs. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or applicable state analog. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit from the U.S. Army Corps of Engineers. The EPA issued a final rule on the federal jurisdictional reach over waters of the United States in 2015, which was repealed by the EPA on October 22, 2019. On January 23, 2020, the EPA and the U.S. Army Corps of Engineers issued the Navigable Waters Protection Rule re-defining the term "waters of the United States" as applied under the Clean Water Act and narrowing the scope of waters subject to federal regulation. The rule is the subject of various legal challenges, and a federal district court in Colorado stayed implementation of the rule. The stay is limited to application of the rule in Colorado; the rule has taken effect in all other states. At President Biden's direction, the EPA and the U.S. Army Corps of Engineers requested the litigation be stayed while the agencies review the rule. The ongoing litigation creates uncertainty regarding federal jurisdiction over waters of the United States.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state and local laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits. As a result, we may need to incur capital costs in order to remain in compliance. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

On June 3, 2016, the EPA expanded its regulatory coverage in the oil and natural gas industry with additional regulated equipment categories, and the addition of new rules limiting methane emissions from new or modified sites and equipment. Although the EPA attempted to suspend enforcement of the methane rule, this action was ruled improper by the U.S. Court of Appeals for the D.C. Circuit on July 2, 2017. Subsequently, in September 2020, the EPA finalized the Reconsideration Rule that substantially changed the obligations associated with methane emissions, limiting obligations for the oil and natural gas industry. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the Reconsideration Rule by September 2021. Separately, in September 2020, the EPA finalized amendments known as the Review Rule that would rescind requirements related to the regulation of methane emissions from the oil and natural gas industry. Both rules are subject to ongoing litigation, and therefore, future obligations continue to remain uncertain under the Clean Air Act.

Climate Change. Numerous reports from scientific and governmental bodies such as the United Nations Intergovernmental Panel on Climate Change have expressed heightened concerns about the impacts of human activity, especially fossil fuel combustion, on the global climate. In turn, governments and civil society are increasingly focused on limiting the emissions of GHGs, including emissions of carbon dioxide from the use of oil and natural gas.

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in 195 countries, including the United States, coming together to develop the so-called “Paris Agreement,” which calls for the parties to undertake “ambitious efforts” to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. The United States formally announced its intent to withdraw from the Paris Agreement on November 4, 2019, which withdrawal was effective on November 4, 2020. On January 20, 2021, President Biden issued written notification to the United Nations of the United States’ intention to rejoin the Paris Agreement, which became effective on February 19, 2021. In addition, certain U.S. city and state governments announced their intention to continue to satisfy their proportionate obligations under the Paris Agreement. In addition, legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the United States, and a number of states have begun taking actions to control and/or reduce emissions of GHGs.

Any legislation or regulatory programs at the federal, state, or city levels designed to reduce GHG emissions could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources, such as policies designed to increase utilization of zero-emissions or electric vehicles, as a means of addressing climate change could reduce demand for the oil and natural gas we produce.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants.

The EPA has established GHG reporting requirements for certain sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although these requirements do not limit the amount of GHGs that can be emitted, they do require us to incur costs to monitor, keep records of, and report GHG emissions associated with our operations.

Parties concerned about the potential effects of climate change have also directed their attention at sources of financing for energy companies, which has resulted in certain financial institutions, funds and other capital providers restricting or eliminating their investment in oil and natural gas activities. In addition, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. Although our business is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions and not at the federal level, as the SDWA expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid, as further discussed below). Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing has been proposed in past legislative sessions but has not passed.

The EPA, however, issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the UIC program, specifically as "Class II" UIC wells. 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 some circumstances," including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. This report could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and business. Further, on June 28, 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, and after a legal challenge by environmental groups, in July 2019, the EPA declined to revise the rules.

On June 3, 2016, the EPA adopted regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards ("NSPS") for hydraulically fractured natural gas and oil wells to address emissions of sulfur dioxide, volatile organic compounds ("VOCs") and methane, with a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule sought to achieve a 95% reduction in VOCs and methane emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured gas and newly constructed or refractured oil wells.

Several states, including Texas, and some municipalities, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure on a website and also file the list of chemicals with the Texas Railroad Commission (the "RRC") with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the RRC.

Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some cases impose a moratorium on, hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; or restrictions on access to, and usage of, water. Further, there has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the U.S. implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations of harm. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of potential federal or state legislation governing hydraulic fracturing. In light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities. A 2015 U.S. Geological Survey report identified eight states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could cause curtailed or decreased demand for our services and have a material adverse effect on our business.

Surface Damage Statutes ("SDAs"). In addition, a number of states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by oil and gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments by the operator to surface owners/users in connection with exploration and operating activities in addition to bonding requirements to compensate for damages to the surface as a result of such activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

National Environmental Policy Act. Oil and natural gas exploration and production activities requiring federal permits may be subject to the National Environmental Policy Act ("NEPA"), which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will evaluate the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a detailed Environmental Impact Statement that must be made available for public review and comment. Recent litigation by environmental non-governmental organizations has alleged that the Environmental Assessments for certain oil and natural gas projects violated NEPA by failing to account for climate change and the greenhouse gas emissions impacts of such projects. On July 16, 2020, the Council on Environmental Quality revised NEPA's implementing regulations in an effort designed to streamline project approvals. Among other revisions, the rules redefines environmental "effects" or "impacts" as the effects "that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives." The rule also eliminated the current "direct," "indirect," or "cumulative" categories of effects. The new regulations are subject to ongoing litigation in several federal district courts and future implementation of the regulations is unclear. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, require federal permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act and Migratory Bird Treaty Act. The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' or its habitat. The U.S. Fish and Wildlife Service (the "FWS") must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. In August 2019, the FWS and National Marine Fisheries Service issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat. A coalition of states and environmental groups have challenged the three rules and the litigation remains pending. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations. We anticipate the rule will be subject to litigation. A final rule amending how critical habitat and suitable habitat areas are designated under the ESA was finalized by the U.S. Fish and Wildlife Service in 2016. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act (the "MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. On January 7, 2021, the Department of the Interior finalized a rule limiting application of the MBTA, however, the Department of the Interior under President Biden delayed the effective date of the rule and opened a public comment period for further review. Future implementation of the rules implementing the Endangered Species Act and the MBTA are uncertain. If the Company was to have a portion of its leases designated as critical or suitable habitat or a protected species were located on a lease, it may adversely impact the value of the affected leases.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local agencies and authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other similar companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation of oil and natural gas is subject to federal regulation by FERC which regulates the terms, conditions and rates for interstate transportation and storage service and various other matters. State regulations govern the rates, terms, and conditions of service associated with access to intrastate oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transportation in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas sales prices are currently unregulated, the federal government historically has been active in the area of oil and natural gas sales regulation. We cannot predict whether new legislation to regulate oil and natural gas sales might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of natural gas, condensate, oil and natural gas liquids are not currently regulated and are made at market prices.

Exports of U.S. Oil Production and Natural Gas Production. In December 2015, the federal government ended its decades-old prohibition of exports of oil produced in the lower 48 states of the U.S. As a result, exports of U.S. oil have increased significantly, reinforcing the general perception in the industry that the end of the U.S. export ban was positive for producers of U.S. oil. In addition, the U.S. Department of Energy authorizes exports of natural gas, including exports of natural gas by pipelines connecting U.S. natural gas production to pipelines in Mexico, and the export of liquefied natural gas ("LNG") through LNG export facilities, the construction and operation of which are regulated by FERC. Since 2016, natural gas produced in the lower 48 states of the U.S. has been exported as LNG from export facilities in the U.S. Gulf Coast region. LNG export capacity has steadily increased in recent years, and is expected to continue increasing due to numerous export facilities that are currently being developed. The industry generally believes that this sustained growth in exports will be a positive development for producers of U.S. natural gas.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas without a permit and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affecting the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Some state agencies and municipalities require bonds or other financial assurances to support those obligations.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production and have it transported. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for "first sales," which include all of our sales of our own production.

Under the Energy Policy Act of 2005 ("EPAct") Congress amended the NGA and NGPA to give FERC substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess civil penalties up to $1.0 million per day for each violation. This maximum penalty authority has been and will continue to be adjusted periodically to account for inflation. EPAct also amended the NGA to authorize FERC to "facilitate transparency in markets for the sale or transportation of physical natural gas in interstate commerce," pursuant to which authorization FERC now requires natural gas wholesale market participants, including a number of entities that may not otherwise be subject to FERC's traditional NGA jurisdiction, to report information annually to FERC concerning their natural gas sales and purchases. FERC requires any wholesale market participant that sells 2.2 million MMBtus or more annually in “reportable” natural gas sales to provide a report, known as FERC Form 552, to FERC. Reportable natural gas sales include sales of natural gas that utilize a daily or monthly gas price index, contribute to index price formation, or could contribute to index price formation, such as fixed price transactions for next-day or next-month delivery.

FERC also regulates interstate natural gas transportation rates, terms and conditions of service, and the terms under which we as a shipper may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and for the release of our excess, if any, natural gas pipeline capacity. In 1985, FERC began promulgating a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate natural gas pipeline companies are required to provide non-unduly discriminatory transportation services to all shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases, sales, and transportation that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated. With the new administration, we are expecting a reversal of the less stringent regulatory approach pursued by FERC and Congress during the Trump administration. Additionally, we cannot determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC’s current regulatory regime, interstate transportation services must be provided on an open-access, non-unduly discriminatory basis at cost-based rates or negotiated rates, both of which are subject to FERC approval. FERC also allows jurisdictional gas pipeline companies to charge market-based rates if the transportation market at issue is sufficiently competitive. The FERC-regulated tariffs, under which interstate pipelines provide such open-access transportation service, contain strict limits on the means by which a shipper releases its pipeline capacity to another potential shipper, which provisions include compliance with FERC’s “shipper-must-have-title” rule. Violations by a shipper (i.e., a pipeline customer) of FERC’s capacity release rules, including the shipper-must-have-title rule could subject a shipper to substantial penalties from FERC.

With respect to its regulation of natural gas pipelines under the NGA, FERC has not generally required the applicant for construction of a new interstate natural gas pipeline to provide information concerning the GHG emissions resulting from the activities of the proposed pipeline’s customers. In August 2017, the U.S. Circuit Court of Appeals for the DC Circuit issued a decision remanding a natural gas pipeline certificate application to FERC, and required FERC to revise its environmental impact statement for the proposed pipeline to analyze potential GHG emission from the specific downstream power plants that the pipeline was designed to serve. To date, FERC has declined to analyze potential upstream GHG emissions that could result from the activities of natural gas producers and marketers, like the Company, to be served by proposed interstate natural gas pipeline projects. However, the scope of FERC’s obligation to analyze the environmental impacts of proposed interstate natural gas pipeline projects, including the upstream indirect impacts of related natural gas production activity, remains subject to ongoing litigation and contested administrative proceedings at FERC and in the courts.

Gathering service, which occurs on pipeline facilities located upstream of FERC-jurisdictional interstate transportation services, is regulated by the states onshore and in state waters. Under NGA section 1(b), gathering facilities are exempt from FERC’s jurisdiction. FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, and FERC applies this test on a case-by-case basis. Depending on changes in the function performed by particular pipeline facilities, FERC has in the past reclassified certain FERC-jurisdictional transportation facilities as non-jurisdictional gathering facilities and FERC has reclassified certain non-jurisdictional gathering facilities as FERC-jurisdictional transportation facilities. Any such changes could result in an increase to our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by the Company are also subject to regulation by the U.S. Department of Transportation (“DOT”) under the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended (“Pipeline Safety Act”), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In addition, PHMSA had initially considered regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In October 2019, PHMSA finalized new safety regulations for hazardous liquid pipelines, including a requirement that operators inspect affected pipelines following extreme weather events or natural disasters, that all hazardous liquid pipelines have a system for detecting leaks and that pipelines in high consequence areas be capable of accommodating in-line inspection tools within twenty years. In addition, PHMSA is in the process of finalizing a rulemaking with respect to gathering lines, but the contents and timing of any final rule for gathering lines are uncertain. In December 2020, Congress passed the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (“PIPES Act of 2020”). In addition to reauthorizing PHMSA, the PIPES Act of 2020 directs the Secretary of Transportation to update or promulgate regulations addressing the safety of certain gas pipeline, gathering, distribution and LNG facilities. Until these future regulations are proposed, it is not possible to determine how they will affect our business.

Oil and NGLs Sales and Transportation. Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

The Company's sales of oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by FERC under the Interstate Commerce Act ("ICA"). FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil and natural gas liquid transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate common carrier oil pipelines must provide service on a non-duly discriminatory basis under the ICA, which is administered by FERC. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

In addition, FERC issued a declaratory order in November 2017, involving a marketing affiliate of an oil pipeline, which held that certain arrangements between an oil pipeline and its marketing affiliate would violate the ICA's anti-discrimination provisions. FERC held that providing transportation service to affiliates at what is essentially the variable cost of the movement, while requiring non-affiliated shippers to pay the filed tariff rate, would violate the ICA. Rehearing has been sought of this FERC order by various parties. Due to the pending rehearing of the order and its recency, the Company cannot currently determine the impact this FERC order may have on oil pipelines, their marketing affiliates, and the price of oil and other liquids transported by such pipelines.

Any transportation of the Company's oil, natural gas liquids and purity components (ethane, propane, butane, iso-butane, and natural gasoline) by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180, including Emergency Orders by the FRA regulations initially established on May 8, 2015 by PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids; PHMSA regulations were subsequently amended to remove certain requirements on September 25, 2018. In July 2020, PHMSA promulgated a final rule allowing bulk transportation of LNG by rail. The rule also incorporates additional safety requirements.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Financial Regulations, Including Regulations Enacted Under the Dodd-Frank Act. The U.S. Commodities and Futures Exchange Commission (the "CFTC") holds authority to monitor certain segments of the physical and futures energy commodities market 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 the Company undertakes, the Company is thus required to observe anti-market manipulation and disruptive trading practices laws and related regulations enforced by FERC and/or the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties.

Congress adopted comprehensive financial reform legislation in 2010, establishing federal oversight and regulation of the over-the-counter derivative market and entities that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), required the CFTC and the U.S. Securities and Exchange Commission ("SEC") to promulgate rules and regulations implementing the legislation, including regulations that affect derivatives contracts that the Company uses to hedge its exposure to price volatility.

While the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas remain pending. The Company cannot, at this time, predict the timing or contents of any final rules the CFTC may enact with regard to any applicable rulemaking proceeding. Any final rule in either proceeding could impact the Company's ability to enter into financial derivative transactions to hedge or mitigate exposure to commodity price volatility and other commercial risks affecting our business.

Worker Health and Safety. We are subject to a number of federal and state laws and regulations, including OSHA, and comparable state statutes, the purpose of which are to protect the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may have impact to our operations. These changes include among other items; record keeping and reporting, revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry and requirements for a safety and health management system. In addition, OSHA's 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.

Commitments and Contingencies

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies included, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities. See "Note 17 - Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for additional information.

Available Information

We make available free of charge on our website (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC.

We also make available within the "About Callon" section of our website our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation, Strategic Planning and Reserves, and Nominating, Environmental, Social and Governance Committee Charters, which have been approved by our Board of Directors. We will make timely disclosure on our website of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: General Counsel, Callon Petroleum Company, 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

ITEM 1A. Risk Factors

Risks Related to the Oil & Natural Gas Industry

Oil and natural gas prices are volatile, and substantial or extended declines in prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which have in recent years been, and we expect will continue to be, extremely volatile. During the five years ended December 31, 2020, NYMEX WTI prices ranged from a high of $77.41 per barrel on June 27, 2018 to a low of -$36.98 per barrel on April 20, 2020, and NYMEX Henry Hub prices ranged from a high of $6.24 per MMBtu on January 2, 2018 to a low of $1.33 per MMBtu on September 21, 2020. Prices were particularly volatile in 2020 as a result of multiple significant factors impacting supply and demand in the global oil and natural gas markets, including those relating to the COVID-19 global pandemic. In 2020, NYMEX WTI crude oil ranged from a high of $63.27 per barrel to a low of -$36.98 per barrel, and the Henry Hub spot market price of gas ranged from a high of $3.14 per MMBtu to a low of $1.33 per MMBtu. The prices of oil and natural gas depend on factors we cannot control, such as macro-economic conditions, levels of production, domestic and worldwide inventories, demand for oil and natural gas, the capacity of U.S. and international refiners to use U.S. supplies of oil, natural gas and NGLs, relative price and availability of alternative forms of energy, actions by non-governmental organizations, OPEC and other countries, legislative and regulatory actions, technology developments impacting energy consumption and energy supply, and weather. These factors make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and non-cancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

In general, prices of oil, natural gas, and NGLs affect the following aspects of our business: our revenues, cash flows, earnings and returns; our ability to attract capital to finance our operations and the cost of the capital; the amount we are allowed to borrow under our Credit Facility; the profit or loss we incur in exploring for and developing our reserves; and the value of our oil and natural gas properties.

A substantial or extended decline in commodity prices may also reduce the amount of oil and natural gas that we can produce economically and cause a significant portion of our development projects to become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending, which could negatively affect our ability to replace our production and our future rate of growth, or require us to borrow funds to cover any such shortfall, which we may be unable to obtain at such time on satisfactory terms.

Due to the commodity price environment, in 2020, we reduced our development plan in order to preserve capital, including the temporary cessation of all drilling and completion activities for most of the second and third quarters of 2020. A sustained period of weakness in oil, natural gas and NGLs prices, and the resultant effects of such prices on our drilling economics and ability to raise capital, will require us to reevaluate and further postpone or eliminate additional drilling. Additionally, as of December 31, 2020, approximately 30% of our total net acreage was not held by production and we had undeveloped leases representing 1% and 21% of our total net acreage scheduled to expire during 2021 and 2022, respectively, in each case assuming no exercise of lease extension options where applicable. The net acreage scheduled to expire in 2022 is substantially comprised of non-core acreage principally located in Texas. If we are required to further curtail our drilling program, we may be unable to continue to hold such leases that are scheduled to expire, which may further reduce our reserves. As a result, if oil, natural gas and/or NGL prices experience a sustained period of weakness, our future business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures may be materially and adversely affected.

If oil and natural gas prices remain depressed for extended periods of time, we may be required to make significant downward adjustments to the carrying value of our oil and natural gas properties. Under the full cost method, which we use to account for our oil and natural gas properties, the net capitalized costs of our oil and natural gas properties may not exceed the PV-10 of our estimated proved reserves, using the 12-Month Average Realized Price, plus the lower of cost or fair market value of our unproved properties. If such net capitalized costs exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly and once incurred, an impairment of evaluated oil and natural gas properties is not reversible at a later date, even if prices increase. See "Note 2 - Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements as well as the Supplemental Information on Oil and Natural Gas Operations for additional information.

A negative shift in investor sentiment of the oil and gas industry could adversely affect our ability to raise debt and equity capital. Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

We face various risks associated with increased activism against oil and natural gas exploration and development activities. Opposition toward oil and natural gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations such as drilling and development.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could materially and adversely affect our operations and profitability. From time to time, our industry experiences a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, during periods in which the levels of exploration and production increase, the demand for, and wages and costs of, drilling rig crews and other experienced personnel, oilfield services and equipment typically also increase, while the quality of these services and equipment may suffer.

An excess supply of oil and natural gas may in the future cause us to reduce production and shut-in our wells, any of which could adversely affect our business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures. As a result of the COVID-19 pandemic and the effects of actions by, or disputes among or between, oil and natural gas producing countries, there is an excess supply of oil, NGLs, and natural gas in the United States, which could continue for a sustained period. This excess supply, in turn, resulted in transportation and storage capacity constraints in the United States in 2020. If, in the future, our transportation or storage arrangements become constrained or unavailable, we may incur significant operational costs if there is an increase in price for services or we may be required to shut-in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Further, any prolonged shut-in of our wells may result in materially decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. All of these impacts may adversely affect our business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures.

Risks Related to the COVID-19 Pandemic

The COVID-19 pandemic, and various governmental actions taken to mitigate its impact, have materially adversely affected, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our business, financial position, results of operations, and cash flows. The COVID-19 pandemic, and various governmental actions taken to mitigate its impact, have negatively impacted the global economy, disrupted global supply chains, created significant volatility and disruption of financial and commodity markets, and resulted in an unprecedented decline in demand for oil and natural gas, which has materially adversely affected our business, financial position, results of operations, and cash flows and exacerbated the potential negative impact from many of the other risks described herein, including those relating to our financial position and debt obligations. Also, for example, the pandemic has increased volatility and caused negative pressure in the capital markets; as a result, we may experience difficulty accessing the capital or financing needed to fund our operations, which have substantial capital requirements, on satisfactory terms or at all, compounding liquidity risks associated with a material reduction in our revenues and cash flows as a result of the decline in demand due to the COVID-19 pandemic.

We expect the COVID-19 pandemic and related economic repercussions to continue to materially and adversely affect our business, financial condition, results of operations, and cash flows. However, the extent of the impact of the COVID-19 pandemic on our business and our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors that we cannot predict, including the following: the severity and duration of the pandemic; governmental, business and other actions in response to the pandemic; the impact of the pandemic on economic activity; the response of the overall economy and the financial markets; the demand for oil and natural gas, which may be reduced on a prolonged or permanent basis due to a structural shift in the global economy in the way people work, travel, and interact, or in connection with a global recession or depression; any impairment in the value of our tangible or intangible assets which could be recorded as a result of a weaker economic conditions or commodity prices; and the potential effects on our internal controls, including those over financial reporting, as a result of changes in working environments, such as shelter-in-place and similar orders that are applicable to our employees and business partners, among others. There are no comparable recent events that provide guidance as to the effect the COVID-19 pandemic may have, and as a result, the ultimate impact of the pandemic is highly uncertain and subject to change.

Operational Risks

Our operations are subject to operating hazards inherent to our industry that may adversely impact our ability to conduct business, and we may not be fully insured against all such operating risks. The operating hazards in exploring for and producing oil and natural gas include: encountering unexpected subsurface conditions that cause damage to equipment or personal injury, including loss of life; equipment failures that curtail or stop production or cause severe damage to or destruction of property, natural resources or other equipment; blowouts or other damages to the productive formations of our reserves that require a well to be re-drilled or other corrective action to be taken; and storms and other extreme weather conditions that cause damages to our production facilities or wells. Because of these or other events, we could experience environmental hazards, including release of oil and natural gas from spills, natural gas leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or fracturing fluids, including chemical additives, underground migration, and ruptures. If we experience any of these problems, we could incur substantial losses in excess of our insurance coverage.

The occurrence of a significant event or claim, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. Also, no assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable to cover our possible losses from operating hazards and we may elect no or minimal insurance coverage.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks. We may invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that any leasehold acreage acquired will be profitably developed, that new wells drilled will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, including wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, we may not be successful in controlling our drilling and production costs to improve our overall return and wells that are profitable may not achieve our targeted rate of return. Wells may have production decline rates that are greater than anticipated. Future drilling and completion efforts may impact production from existing wells, and parent-child effects may impact future well productivity as a result of timing, spacing proximity or other factors. Failure to conduct our oil and gas operations in a profitable manner may result in write- downs of our proved reserves quantities, impairment of our oil and gas properties, and a write-down in the carrying value of our unproved properties, and over time may adversely affect our growth, revenues and cash flows.

Multi-well pad drilling may result in volatility in our operating results. We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad, which would further cause delays in the scheduled commencement of production or interruptions in ongoing production. These delays or interruptions may cause volatility in our operating results. Further, any delay, reduction or curtailment of our development and producing operations due to operational delays caused by multi-well pad drilling could result in the loss of acreage through lease expirations.

Restrictions on our ability to obtain, recycle and dispose of water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner. Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local land owners and other third party sources for use in our operations. If drought conditions were to occur or demand for water were to outpace supply, our ability to obtain water could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly. Along with the risks of other extreme weather events, drought risk, in particular, is likely increased by climate change. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows. In addition, significant amounts of water are produced in our operations. Inadequate access to or availability of water recycling or water disposal facilities could adversely affect our production volumes or significantly increase the cost of our operations.

Risks Related to Marketing and Transportation

Factors beyond our control, including the availability and capacity of gas processing facilities and pipelines and other transportation operations owned and operated by third parties, affect the marketability of our production. The ability to market oil and natural gas from our wells depends upon numerous factors beyond our control. A significant factor in our ability to market our production is the availability and capacity of gas processing facilities and pipeline and other transportation operations, including trucking services, owned and operated by third parties. These facilities and services may be temporarily unavailable to us due to market conditions, physical or mechanical disruption, weather, lack of contracted capacity, pipeline safety issues, or other reasons. In addition, in certain newer development areas, processing and transportation facilities and services may not be sufficient to accommodate potential production and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built. Our failure to obtain access to processing and transportation facilities and services on acceptable terms could materially harm our business. We may be required to shut in wells for lack of a market or because of inadequate or unavailable processing or transportation capacity. If that were to occur, we would be unable to realize revenue from those wells until transportation arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases. If we were required to shut in our production for long periods of time due to lack of transportation capacity, it would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Other factors that affect our ability to market our production include:

- the extent of domestic production and imports/exports of oil and natural gas;
- federal regulations authorizing exports of LNG, the development of new LNG export facilities under construction in the U.S. Gulf Coast region, and the first LNG exports from such facilities;
- the construction of new pipelines capable of exporting U.S. natural gas to Mexico and transporting Eagle Ford and Permian oil production to the Gulf Coast;
- the proximity of hydrocarbon production to pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather; and
- state and federal regulation of oil, natural gas and NGL marketing and transportation.

We have entered into firm transportation contracts that require us to pay fixed sums of money regardless of quantities actually shipped. If we are unable to deliver the minimum quantities of production, such requirements could adversely affect our results of operations, financial position, and liquidity. We have entered into firm transportation agreements for a portion of our production in certain areas in order to improve our ability, and that of our purchasers, to successfully market our production. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements. Additionally, these agreements obligate us to pay fees on minimum volumes regardless of actual throughput. If we have insufficient production to meet the minimum volumes, the requirements to pay for quantities not delivered could have an impact on our results of operations, financial position, and liquidity.

Risks Related to Our Reserves and Drilling Locations

Our estimated reserves are based on interpretations and assumptions that may be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. This Annual Report contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. These assumptions include those required by the SEC relating to 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 the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this 2020 Annual Report on Form 10-K. Additionally, estimates of reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas.

You should not assume that any PV-10 of our estimated proved reserves contained in this 2020 Annual Report on Form 10-K represents the market value of our oil and natural gas reserves. We base the PV-10 from our estimated proved reserves at December 31, 2020 on the 12-Month Average Realized Price and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. Recovery of PUDs generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these PUDs and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the discount factor used to calculate PV-10 may not be appropriate based on our cost of capital from time to time and the risks associated with our business and the oil and gas industry.

Unless we replace our oil and gas reserves, our reserves and production will decline. Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues, reserve quantities and cash flows will decline. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. We may not be successful in finding, developing or acquiring additional reserves, and our efforts may not be economic. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, availability and cost of drilling, completion and production services and equipment, lease expirations, regulatory approvals, and other factors discussed in these risk factors. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

The development of our PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Developing PUDs requires significant capital expenditures and successful drilling operations, and a substantial amount of our proved reserves are PUDs which may not be ultimately developed or produced. Approximately 55% of our total estimated proved reserves as of December 31, 2020 were PUDs. The reserve data included in the reserve reports of our independent petroleum engineers assume significant capital expenditures will be made to develop such reserves. We cannot be certain that the estimated capital expenditures to develop these reserves are accurate, that development will occur as scheduled, or that the results of such development will be as estimated. We may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including: unexpected drilling conditions; pressure or irregularities in formations; lack of proximity to and shortage of capacity of transportation facilities; equipment failures or accidents and shortages or delays in the availability of drilling rigs, equipment, personnel and services; the availability of capital; and compliance with governmental requirements. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated PUDs and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Risks Related to Technology

We may not be able to keep pace with technological developments in our industry. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats. A cyberattack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation or financial loss. The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our technologies, systems, networks, seismic data, reserves information or other proprietary information, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation or potential liability. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyberattack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the U.S. government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyberattacks 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 vulnerability to cyberattacks.

Risks Related to Our Indebtedness and Financial Position

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings from financial institutions, the sale of public debt and equity securities and asset dispositions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, participation of non-operating working interest owners, the cost and availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

If the ability to borrow under our Credit Facility or our cash flows from operations decrease, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. The failure to obtain additional financing on terms acceptable to us, or at all, could result in a curtailment of our development activities and could adversely affect our business, financial condition and results of operations.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects. As of December 31, 2020, we had aggregate outstanding indebtedness of approximately $3.0 billion. Our amount of indebtedness could affect our operations in many ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limiting management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increasing our vulnerability to downturns and adverse developments in our business and the economy;
- limiting our ability to access the capital markets to raise capital on favorable terms, to borrow under our Credit Facility or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- making it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings;
- making us vulnerable to increases in interest rates as our indebtedness under our Credit Facility may vary with prevailing interest rates;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness or less restrictive terms governing their indebtedness; and
- making it more difficult for us to satisfy our obligations under our senior notes or other debt and increasing the risk that we may default on our debt obligations.

Restrictive covenants in the agreements governing our indebtedness may limit our ability to respond to changes in market conditions or pursue business opportunities. Our Credit Facility and the indentures governing our senior notes contain restrictive covenants that limit our ability to, among other things: incur additional indebtedness including secured indebtedness; make investments; merge or consolidate with another entity; pay dividends or make certain other payments; hedge future production or interest rates; create liens that secure indebtedness; repurchase securities; sell assets; or engage in certain other transactions without the prior consent of the holders or lenders. As a result of these covenants, we are limited in the manner in which we conduct our business and we may be unable to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

In addition, our Credit Facility requires us to maintain certain financial ratios and to make certain required payments of principal, premium, if any, and interest. If we fail to comply with these provisions or other financial and operating covenants in the Credit Facility or the indentures governing our senior notes, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our Credit Facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and we could be forced into bankruptcy or liquidation.

Adverse changes in our credit rating may affect our borrowing capacity and borrowing terms. Our outstanding debt is periodically rated by nationally recognized credit rating agencies. The credit ratings are based on our operating performance, liquidity and leverage ratios, overall financial position, and other factors viewed by the credit rating agencies as relevant to our industry and the economic outlook. Our credit rating may affect the amount of capital we can access, as well as the terms of any financing we may obtain. Because we rely in part on debt financing to fund growth, adverse changes in our credit rating may have a negative effect on our future growth.

Our borrowings under our Credit Facility expose us to interest rate risk. Our earnings are exposed to interest rate risk associated with borrowings under our Credit Facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.00% to 3.00% depending on the interest rate used and the amount of the loan outstanding in relation to the borrowing base.

The ability to borrow under our Credit Facility may be restricted to an amount below the amount of borrowings outstanding thereunder or to a lesser amount than what we expect due to future borrowing base reductions or restrictions contained in our other debt agreements. The borrowing base and elected commitment amount under our Credit Facility is currently $1.6 billion, and as of December 31, 2020, we had an aggregate principal balance of $985.0 million outstanding thereunder. Our borrowing base is subject to redeterminations semi-annually, and a future decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations may cause us to not be able to access adequate funding under the Credit Facility. The lenders have sole discretion in determining the amount of the borrowing base and may cause our borrowing base to be redetermined to a materially lower amount, including to below our outstanding borrowings as of such redetermination. In addition, our other debt agreements contain restrictions on the incurrence of additional debt and liens which could limit our ability to borrow under our Credit Facility. If our borrowing base were to be reduced, or if covenants in our indentures restrict our ability to access funding under the Credit Facility, we may be unable to implement our 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 and impair our ability to service our indebtedness. In addition, we cannot borrow amounts above the elected commitments, even if the borrowing base is greater, without new commitments being obtained from the lenders for such incremental amounts above the elected commitments. In the event the amount outstanding under our Credit Facility exceeds the elected commitments, we must repay such amounts immediately in cash. In the event the amount outstanding under our Credit Facility exceeds the redetermined borrowing base, we are required to either (i) grant liens on additional oil and gas properties (not previously evaluated in determining such borrowing base) with a value equal to or greater than such excess, (ii) repay such excess borrowings over six monthly installments, or (iii) elect a combination of options in clauses (i) and (ii). We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, an event of default would occur under our Credit Facility.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful. Our ability to make scheduled payments on or to refinance our indebtedness obligations depends on our financial condition and operating performance, which are subject to certain financial, economic, competitive and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Also, we may not be able to consummate dispositions at such time on terms acceptable to us or at all, and the proceeds of any such dispositions may not be adequate to meet such debt service obligations. Furthermore, any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. In addition, the terms of existing or future debt instruments may restrict us from adopting some of these alternatives. For example, our Credit Facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition.

Any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness.

We cannot be certain that we will be able to maintain or improve our leverage position. An element of our business strategy involves maintaining a disciplined approach to financial management. However, we are also seeking to acquire, exploit and develop additional reserves that may require the incurrence of additional indebtedness. Although we will seek to maintain or improve our leverage position, our ability to maintain or reduce our level of indebtedness depends on a variety of factors, including future performance and our future debt financing needs. General economic conditions, oil and natural gas prices and financial, business and other factors will also affect our ability to maintain or improve our leverage position. Many of these factors are beyond our control.

Risks Related to Acquisitions

We may be unable to integrate successfully the operations of acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. We have completed, and may in the future complete, acquisitions that include undeveloped acreage. We can offer no assurance that we will achieve the desired profitability from our acquisitions, including the Carrizo Acquisition, or from any acquisitions we may complete in the future. In addition, failure to integrate future acquisitions successfully could adversely affect our financial condition and results of operations.

Our acquisitions may involve numerous risks, including those related to:

- operating a larger, more complex combined organization and adding operations;
- assimilating the assets and operations of the acquired business, especially if the assets acquired are in a new geographic area;
- acquired oil and natural gas reserves not being of the anticipated magnitude or as developed as anticipated;
- the loss of significant key employees, including from the acquired business;
- the inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity if we use a portion of our available cash to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the diversion of management's attention from other business concerns, which could result in, among other things, performance shortfalls;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- coordinating or consolidating corporate and administrative functions;
- inconsistencies in standards controls, procedures and policies; and
- integrating relationships with customers, vendors and business partners.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of our two companies, may not initially offset integration-related costs or achieve a net benefit in the near term or at all.

If we consummate any future acquisitions, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. The inability to effectively manage the integration of acquisitions could reduce our focus on current operations, which in turn, could negatively impact our future results of operations.

We may fail to fully identify problems with any properties we acquire, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Texas or other regions in the future. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, adequacy of title, operating and capital costs, and potential environmental and other liabilities. Although we conduct a review that we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify. Such assessments are inexact and their accuracy is inherently uncertain. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface, title and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Risks Related to Our Hedging Program

Our hedging program may limit potential gains from increases in commodity prices, result in losses, or be inadequate to protect us against continuing and prolonged declines in commodity prices. We enter into arrangements to hedge a portion of our production from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2020 are in the form of collars, swaps, put and call options, basis swaps, and other structures placed with the commodity trading branches of certain national banking institutions and with certain other commodity trading groups. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. We cannot be certain that the hedging transactions we have entered into, or will enter into, will adequately protect us from continuing and prolonged declines in oil and natural gas prices. To the extent that oil and natural gas prices remain at current levels or decline further, we would not be able to hedge future production at the same pricing level as our current hedges and our results of operations and financial condition may be negatively impacted.

In addition, in a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of physical production.

Our production is not fully hedged, and we are exposed to fluctuations in oil, natural gas and NGL prices and will be affected by continuing and prolonged declines in oil, natural gas and NGL prices. Our production is not fully hedged, and we are exposed to fluctuations in oil, natural gas and NGL prices and will be affected by continuing and prolonged declines in oil, natural gas and NGL prices. The total volumes which we hedge through use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 60% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our revolving credit facility. We intend to continue to hedge our production, but we may not be able to do so at favorable prices. Accordingly, our revenues and cash flows are subject to increased volatility and may be subject to significant reduction in prices which would have a material negative impact on our results of operations.

Our hedging transactions expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract, particularly during periods of falling commodity prices. Disruptions in the financial markets or other factors outside our control could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform, and even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending on market conditions at the time. If the creditworthiness of any of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Legal and Regulatory Risks

We are subject to stringent and complex federal, state and local laws and regulations which require compliance that could result in substantial costs, delays or penalties. Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. For a discussion of the material regulations applicable to us, see "Business and Properties—Regulations." These laws and regulations may:

- require that we acquire permits before commencing drilling;
- regulate the spacing of wells and unitization and pooling of properties;
- impose limitations on production or operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment or used in connection with drilling and production activities or restrict the disposal of waste from our operations;
- limit or prohibit drilling activities on protected areas, such as wetlands and wilderness;
- impose penalties or other sanctions for accidental or unpermitted spills or releases from our operations; or
- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or decommissioning abandoned wells and production facilities.

Significant expenditures may be required to comply with governmental laws and regulations applicable to us. In addition, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, permit revocations, requirements for additional pollution controls or injunctions limiting or prohibiting operations.

The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as emissions control, permitting, or waste handling, storage, transport, remediation or disposal for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry recently has been the subject of increased legislative and regulatory attention with respect to public health and environmental matters. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term.

Further, under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. Certain environmental statutes, including RCRA, CERCLA, OPA and analogous state laws and regulations, impose strict, joint and several liability for costs required to investigate, clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released (i.e., liability may be imposed regardless of whether the current owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred). We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine and other equipment emissions, GHGs and hydraulic fracturing. Under common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability in excess of our insurance coverage or we may be required to curtail or cease production from properties in the event of environmental incidents.

Federal legislation and state and local legislative and regulatory initiatives relating to hydraulic fracturing and water disposal wells could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production and is typically regulated by state oil and gas commissions. However, from time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing. Legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and to require federal permitting and regulatory control of hydraulic fracturing but has not passed. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in February 2014, the EPA published permitting guidance addressing the use of diesel fuel in hydraulic fracturing operations, and issued an interpretive memorandum clarifying that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. The EPA has also published air emission standards for certain equipment, processes and activities across the oil and natural gas sector, although the EPA finalized amendments in September 2020 that rescind requirements related to the regulation of methane emissions, known as the Reconsideration Rule. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the Reconsideration Rule by September 2021. Separately, in September 2020, the EPA finalized the Review Rule, rescinding requirements related to the regulations of methane emissions from the oil and natural gas industry. Both rules are subject to ongoing litigation; therefore, the scope of future obligations continues to remain uncertain. As a result, future implementation of methane rules by the EPA is uncertain at this time. However, given the long-term trend towards increasing regulation, future federal regulation of methane and other greenhouse gas emissions from the oil and gas industry remains a possibility.

In some areas of Texas, including the Eagle Ford and Permian, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the RRC is reviewing the data to determine whether any regulatory action is necessary to address this issue. If the RRC were to decline to issue permits for, or limit the volumes of, new injection wells into the formations that we currently utilize, we may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase our costs.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas law requires the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public. Furthermore, the RRC issued the "well integrity rule" in May 2013, which includes testing and reporting requirements, such as (i) the requirement to submit to the RRC cementing reports after well completion or cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. Additionally, in October 2014, the RRC adopted a rule requiring applicants for certain new water disposal wells to conduct seismic activity searches using the U.S. Geological Survey to determine the potential for earthquakes within a circular area of 100 square miles. The rule also clarifies the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general or hydraulic fracturing in particular.

In December 2016, the EPA released its final report "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States." This report concludes that hydraulic fracturing can impact drinking water resources in certain circumstances but also noted that certain data gaps and uncertainties limited EPA's ability to fully characterize the severity of impacts or calculate the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle. This study could result in additional regulatory scrutiny that could restrict our ability to perform hydraulic fracturing and increase our costs of compliance and doing business.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, water usage and the potential for impacts to surface water, groundwater and the environment generally, and a number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing or water disposal wells are adopted, such laws could make it more difficult or costly for us to drill for and produce oil and natural gas as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, permitting delays and potential increases in costs. These changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Climate change legislation or regulations restricting emissions of GHG, changes in the availability of financing for fossil fuel companies, and physical effects from climate change could adversely impact our operating costs and demand for the oil and natural gas we produce. In recent years, federal, state and local governments have taken steps to reduce emissions of GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Several states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed GHG rules and regulations, see "Business and Properties—Regulations."

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in nearly 200 countries, including the United States, coming together to develop the Paris Agreement, which calls for the parties to undertake "ambitious efforts" to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. The United States formally announced its intent to withdraw from the Paris Agreement on November 4, 2019, which withdrawal became effective on November 4, 2020. On January 20, 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on February 19, 2021. In addition, certain U.S. city and state governments announced their intention to continue to satisfy their proportionate obligations under the Paris Agreement. A number of states have begun taking actions to control or reduce emissions of GHGs. Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Moreover, incentives or requirements to conserve energy, use alternative energy sources, reduce GHG emissions in product supply chains, and increase demand for low-carbon fuel or zero-emissions vehicles, could reduce demand for the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

In addition, fuel conservation measures, alternative fuel requirements and increasing consumer demand for alternatives to oil and natural gas could reduce demand for oil and natural gas. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could impact our business activities, operations and ability to access capital. Furthermore, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. Although our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects.

Current or proposed financial legislation and rulemaking 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. Title VII of the Dodd-Frank Act establishes federal oversight and regulation of over-the-counter derivatives and requires the CFTC and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas, including the scope of relevant definitions or exemptions, remain pending. The CFTC issued a final rule on margin requirements for uncleared swap transactions in January 2016, which it amended in November 2018. The final rule as amended includes an exemption for certain commercial end-users that enter into uncleared swaps in order to hedge bona fide commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exception from the requirement to use cleared exchanges (rather than hedging over-the-counter) for commercial end-users who use swaps to hedge their commercial risks. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. On January 24, 2020, U.S. banking regulators published a new approach for calculating the quantum of exposure of derivative contracts under their regulatory capital rules. This approach to measuring exposure is referred to as the standardized approach for counterparty credit risk or SA-CCR. It requires certain financial institutions to comply with significantly increased capital requirements for over-the-counter commodity derivatives beginning on January 1, 2022. In addition, on September 15, 2020, the CFTC issued a final rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, which has a compliance date of October 6, 2021. These two sets of regulations and the increased capital requirements they place on certain financial institutions may reduce the number of products and counterparties in the over-the-counter derivatives market available to us and could result in significant additional costs being passed through to end-users like us. On January 14, 2021, the CFTC published a final rule on position limits for certain commodities futures and their economically equivalent swaps, though like several other rules there is a bona fide hedging exemption to the application of such rule. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

Depending on our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, the final rules may provide beneficial exemptions and/or may require us to comply with position limits and other limitations with respect to our financial derivative activities. After the compliance date for the final rule on capital requirements, the Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to cease their current business as hedge providers or spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. These potential changes could reduce the liquidity of the financial derivatives markets which would reduce the ability of commercial end-users like us to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of future swaps relative to the terms of our existing financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

If we reduce our use of derivative contracts as a result of any of the foregoing new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could 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 our consolidated financial position, results of operations, or cash flows.

Tax Risks

Our ability to use our existing net operating loss ("NOL") carryforwards or other tax attributes could be limited. A significant portion of our NOL carryforward balance was generated prior to the effective date of new limitations on utilization of NOLs imposed by the Tax Cuts and Jobs Act of 2017 (the "Tax Act") and are allowable as a deduction against 100% of taxable income in future years, but will start to expire in the 2035 taxable year. The remainder were generated following such effective date, and thus generally allowable as a deduction against 80% of taxable income in future years (with an exception to this rule due to the enactment of the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act"), whereby the utilization of NOLs has been temporarily expanded for taxable years beginning before 2021). Utilization of any NOL carryforwards depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 ("Section 382") of the Internal Revenue Code of 1986, as amended (the "Code"), generally imposes, upon the occurrence of an ownership change (discussed below), an annual limitation on the amount of our pre-ownership change NOLs we can utilize to offset our taxable income in any taxable year (or portion thereof) ending after such ownership change. The limitation is generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax exempt rate. In general, an ownership change occurs if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. Future ownership changes and/or future regulatory changes could further limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations. We are subject to income taxes in the U. S., and our domestic tax assets and liabilities are subject to the allocation of expenses in differing jurisdictions. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including the following: changes in the valuation of our deferred tax assets and liabilities; expected timing and amount of the release of any tax valuation allowances; tax effects of stock-based compensation; costs related to intercompany restructurings; changes in tax laws, regulations or interpretations thereof; or lower than anticipated future earnings in our taxing jurisdictions. In addition, we may be subject to audits of our income, sales and other transaction taxes by U.S. federal and state authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

Tax laws and regulations may change over time and such changes could adversely affect our business and financial condition. From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) changes to a depletion allowance for oil and natural gas properties, (iii) the implementation of a carbon tax, (iv) an extension of the amortization period for certain geological and geophysical expenditures, (v) changes to tax rates and (vi) the introduction of a minimum tax. While these specific changes were not included in the Tax Act or the CARES Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

Other Material Risks

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies and smaller independents as well as numerous financial buyers. Some of our competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment, personnel and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

All of our producing properties are located in the Permian of West Texas and the Eagle Ford of South Texas, making us vulnerable to risks associated with operating in only two geographic regions. As a result of this concentration, as compared to companies that have a more diversified portfolio of properties, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services, or market limitations or interruption of the processing or transportation of oil, natural gas or NGLs. Such delays, interruptions or limitations could have a material adverse effect on our financial condition and results of operations. In addition, the effect of fluctuations on supply and demand may be more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions.

The results of our planned development programs in new or emerging shale development areas and formations may be subject to more uncertainties than programs in more established areas and formations, and may not meet our expectations for reserves or production. The results of our horizontal drilling efforts in emerging areas and formations of the Permian are generally more uncertain than drilling results in areas that are more developed and have more established production from horizontal formations. Because emerging areas and associated target formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis to predict our future drilling results. In addition, horizontal wells drilled in shale formations, as distinguished from vertical wells, utilize multilateral wells and stacked laterals, all of which are subject to well spacing, density and proration requirements of the RRC, which requirements could adversely impact our ability to maximize the efficiency of our horizontal wells related to reservoir drainage over time. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results in these areas are less than anticipated or we are unable to execute our drilling program in these areas because of capital constraints, access to gathering systems and takeaway capacity or otherwise, or natural gas and oil prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees, and third party consultants, many of whom are not subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results. Our principal exposure to credit risk is through receivables resulting from the sale of our oil and natural gas production, advances to joint interest parties and joint interest receivables. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately 31% of our total revenues for the year ended December 31, 2020. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our bylaws designate the Court of Chancery of the State of Delaware (the "Court of Chancery") as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our shareholders, which could limit our shareholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees. Our bylaws provide that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action or proceeding asserting a claim for breach of a fiduciary duty owed by any current or former director, officer, or other employee of our company to us or our shareholders, (iii) any action or proceeding asserting a claim against us or any current or former director, officer, or other employee of our company arising pursuant to any provision of the Delaware General Corporate Law (the "DGCL") or our charter or bylaws (as each may be amended from time to time), (iv) any action or proceeding asserting a claim against us or any current or former director, officer, or other employee of our company governed by the internal affairs doctrine, or (v) any action or proceeding as to which the DGCL confers jurisdiction on the Court of Chancery shall be the Court of Chancery or, if and only if the Court of Chancery lacks subject matter jurisdiction, any state court located within the State of Delaware or, if and only if such state courts lack subject matter jurisdiction, the federal district court for the District of Delaware, in all cases to the fullest extent permitted by law and subject to the court's having personal jurisdiction over the indispensable parties named as defendants.

Our exclusive forum provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce the forum selection provision with respect to such claims, and in any event, our shareholders would not be deemed to have waived our compliance with federal securities laws and the rules and regulations thereunder.

Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our shareholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect its business, financial condition, prospects, or results of operations.

Provisions of our charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for our common stock. Provisions in our certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which we are not the surviving company and may otherwise prevent or slow changes in our Board of Directors and management. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the DGCL. These provisions could discourage an acquisition of the Company or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for our common stock.

We have no current plans to pay cash dividends on our common stock. Our Credit Facility and the indentures governing our senior notes limit our ability to pay dividends and make other distributions. We have no current plans to pay dividends on our common stock and any future determination as to the declaration and payment of cash dividends will be at the discretion of our Board of Directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our Board of Directors at the time of such determination. Consequently, unless we revise our dividend plans, a shareholder's only opportunity to achieve a return on its investment in us will be by selling its shares of our common stock at a price greater than the shareholder paid for it. There is no guarantee that the price of our common stock that will prevail in the market will exceed the price at which a shareholder purchased its shares of our common stock.

General Risk Factors

We may be subject to the actions of activist shareholders. We have been the subject of an activist shareholder in the past. Responding to shareholder activism can be costly and time-consuming, disrupt our operations and divert the attention of management and our employees from executing our business plan. Activist campaigns can create perceived uncertainties as to our future direction, strategy or leadership and may result in the loss of potential business opportunities, harm our ability to attract new investors, customers and joint venture partners and cause our stock price to experience periods of volatility or stagnation. Moreover, if individuals are elected to our Board of Directors with a specific agenda, our ability to effectively and timely implement our current initiatives, retain and attract experienced executives and employees and execute on our long-term strategy may be adversely affected.

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of our common stock or other securities may dilute a shareholder's ownership in us. In the future, we may issue securities to raise capital. We may also acquire interests in other companies by using any combination of cash and our common stock or other securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share or have an adverse impact on the price of our common stock. In addition, secondary sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. Any such reduction in the market price of our common stock could impair our ability to raise additional capital through the sale of our securities.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. While the outcome of these events cannot be predicted with certainty, we believe that the ultimate resolution of any such actions will not have a material effect on our financial position or results of operations.

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

Market Information

Our common stock trades on the New York Stock Exchange (“NYSE”) under the symbol “CPE”.

Reverse Stock Split

On August 7, 2020, the Board of Directors effected a reverse stock split of the Company’s outstanding shares of common stock at a ratio of 1-for-10 and proportionately reduced the total number of authorized shares of the Company’s common stock pursuant to an amendment to the Company’s Certificate of Incorporation, which was approved by the Company’s shareholders at the Company’s annual meeting of shareholders on June 8, 2020. The reverse stock split became effective as of the close of business on August 7, 2020. The Company’s common stock began trading on a split-adjusted basis on the NYSE at the market open on August 10, 2020. All share and per share amounts in this Annual Report on Form 10-K for periods prior to August 7, 2020 have been retroactively adjusted to reflect the reverse stock split. The par value of the common stock was not adjusted as a result of the reverse stock split.

Holders

As of February 19, 2021 the Company had approximately 1,569 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date and presently do not expect to declare or pay any cash dividends on our common stock as we intend to reinvest our cash flows and earnings into our business and pay down debt. The declaration and payment of dividends is subject to the discretion of our Board of Directors and to certain limitations imposed under Delaware corporate law and the agreements governing our debt obligations. The timing, amount and form of dividends, if any, will depend on, among other things, our results of operations, financial condition, cash requirements and other factors deemed relevant by our Board of Directors. In addition, certain of our debt facilities contain restrictions on the payment of dividends to the holders of our common stock.

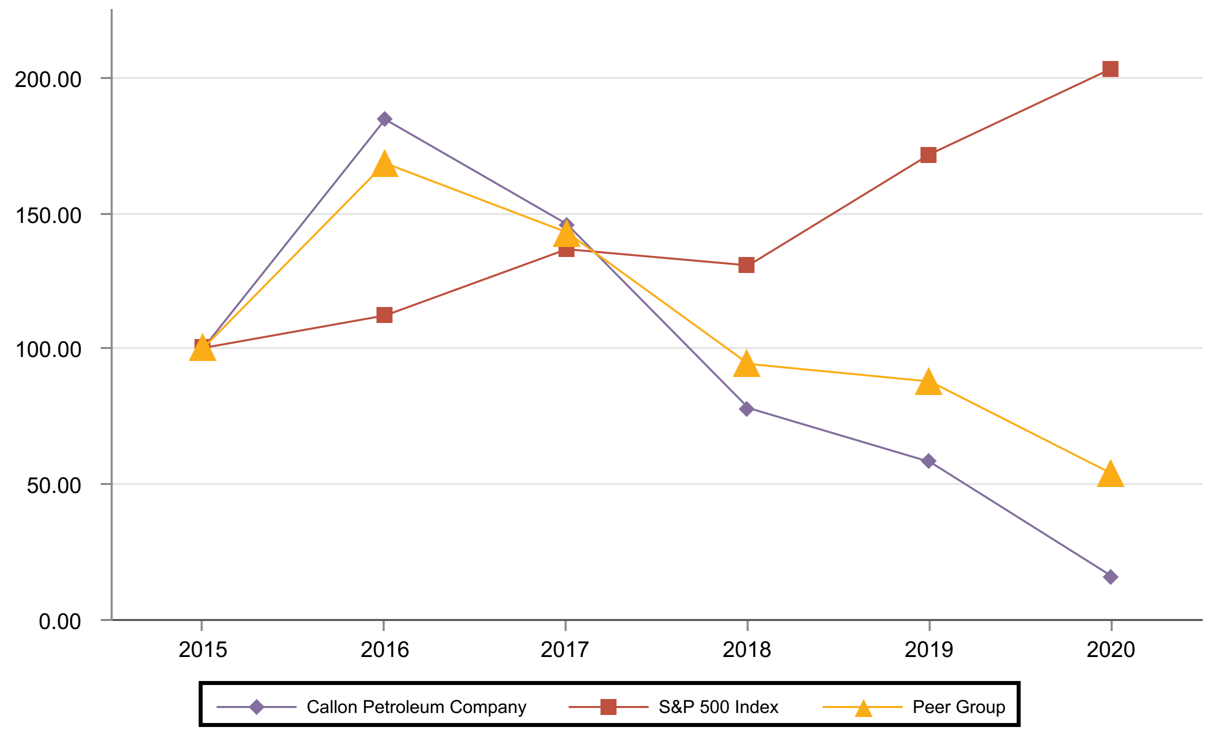
Performance Graph

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to a broad-based stock performance index and a peer group of companies. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph below compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's 500 Index ("S&P 500 Index") and a peer group of companies to which we compare our performance from December 31, 2015 through December 31, 2020. The companies in the peer group include Cimarex Energy Co., Centennial Resource Development, Inc., Magnolia Oil & Gas Corporation, Matador Resources, Inc., Parsley Energy, Inc., PDC Energy, Inc., QEP Resources, Inc., SM Energy Company, and WPX Energy, Inc.

The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing

Comparison of Five Year Cumulative Total Return
Assumes Initial Investment of $100
December 31, 2020



	Years Ended December 31,					
Company/Market/Peer Group	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Callon Petroleum Company	$100	$184	$146	$78	$58	$16
S&P 500 Index - Total Returns	100	112	136	130	172	203
Peer Group	100	168	143	94	88	54

ITEM 6. Selected Financial Data

None.

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

A discussion and analysis of the Company's financial condition and results of operations for the year ended December 31, 2018 can be found in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of its Annual Report on Form 10-K for the year ended December 31, 2019, which was filed with the SEC on February 28, 2020.

General

The following management's discussion and analysis describes the principal factors affecting our results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing.

All of our filings with the SEC are available free of charge through our website (www.callon.com) as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this 2020 Annual Report on Form 10-K.

We are an independent oil and natural gas company incorporated in the State of Delaware in 1994, but our roots go back over 70 years to our Company's establishment in 1950. We are focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. Our activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas, as well as the Eagle Ford, which we entered into through the Carrizo Acquisition in late 2019.

Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals in the Permian, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales, and the Eagle Ford. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and through acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps.

Recent Developments

February Winter Storm

In February 2021, severe winter storms affected field operations in both the Permian and Eagle Ford resulting in the shut-in of nearly 100% of our operated production. Currently, we have returned nearly all of our Eagle Ford and Midland Basin wells to production and expect to have all of our Delaware well production returned by the end of February. The impact to our drilling and completion operations were not significant enough to alter our expectations for the full year development schedule.

COVID-19 Outbreak and Global Industry Downturn

The worldwide outbreak of COVID-19 in 2020, the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19, have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. These dual demand and supply shocks caused oil prices to collapse at the end of the first quarter of 2020 as well as created an excess supply of oil in the United States, which could continue for a sustained period; this is in addition to recent and continued excess supply of natural gas in the United States. This excess supply, in turn, resulted in transportation and storage capacity constraints in the United States during 2020, although these constraints have recently lessened and inventories have declined from peak levels.

Our expectation is that commodity prices, which are the most significant factors impacting our profitability, will remain cyclical and volatile. While commodity prices have recently increased to pre-COVID-19 levels, there is no assurance of how long they will remain at these levels.

2020 Highlights

Operational

- Our total production in 2020 increased by 147% to 37.2 MMBoe (63% oil) as compared to 2019 primarily as a result of the Carrizo Acquisition in late 2019 and wells placed on production during 2020 as a result of our horizontal drilling program.

- Although our actual 2020 operational capital expenditures were approximately 50% or our original operational capital budget as a result of COVID-19 and the macro-economic environment, we drilled 91 gross (86.0 net) horizontal well and completed 90 gross (81.4 net) horizontal wells for the year ended December 31, 2020 and had, as of December 31, 2020, 65 gross (62.1 net) horizontal wells awaiting completion.
- Estimated proved reserves as of December 31, 2020 were 475.9 MMBoe (61% oil), with 45% classified as proved developed.

Financing

- On November 13, 2020, we exchanged $389.0 million of aggregate principal amount of our existing Senior Unsecured Notes for $216.7 million aggregate principal amount of November 2020 Second Lien Notes and 1.75 million November 2020 Warrants. This exchange resulted in the removal of approximately $172.3 million from the long-term debt balance in our consolidated balance sheets.
- On September 30, 2020, we issued $300.0 million of aggregate principal amount of September 2020 Second Lien Notes and 7.3 million September 2020 Warrants for proceeds, net of issuance costs, of approximately $288.6 million.
- As of December 31, 2020, our Credit Facility had a borrowing base and elected commitment amount of $1.6 billion and $985.0 million of borrowings outstanding as compared to borrowings outstanding as of December 31, 2019 of $1.3 billion.

Divestitures

- On September 30, 2020, we sold an undivided 2.0% (on an 8/8ths basis) overriding royalty interest, proportionately reduced to our net revenue interest, in and to our operated leases, excluding certain interests (“ORRI Transaction”) for net proceeds of $135.8 million, which were used to repay borrowings outstanding under the Credit Facility.
- On November 2, 2020, we sold substantially all of our non-operated assets for net proceeds of $29.6 million, subject to post-closing adjustments, which were used to repay borrowings outstanding under the Credit Facility.

Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	Years Ended December 31,			
	2020	2019 [(1)]	$ Change	% Change
Total production [(2)]				
Oil (MBbls)				
Permian	14,113	11,365	2,748	24%
Eagle Ford	9,430	300	9,130	3,043%
Total oil (MBbls)	23,543	11,665	11,878	102%
Natural gas (MMcf)				
Permian	32,087	19,484	12,603	65%
Eagle Ford	8,714	234	8,480	3,624%
Total natural gas (MMcf)	40,801	19,718	21,083	107%
NGLs (MBbls)				
Permian	5,390	93	5,297	5,696%
Eagle Ford	1,460	42	1,418	3,376%
Total NGLs (MBbls)	6,850	135	6,715	4,974%
Total production (MBoe)				
Permian	24,851	14,705	10,146	69%
Eagle Ford	12,342	381	11,961	3,139%
Total barrels of oil equivalent (MBoe)	37,193	15,086	22,107	147%
Total daily production (Boe/d)	101,620	41,331	60,289	146%
Oil as % of total daily production	63 %	77 %		
Benchmark prices[(3)]				
WTI (per Bbl)	$39.38	$56.98	($17.60)	(31%)
Henry Hub (per Mcf)	2.13	2.56	(0.43)	(17%)
Average realized sales price (excluding impact of settled derivatives)				
Oil (per Bbl)				
Permian	$37.23	$54.13	($16.90)	(31%)
Eagle Ford	34.49	59.57	(25.08)	(42%)
Total oil (per Bbl)	36.13	54.27	(18.14)	(33%)
Natural gas (per Mcf)				
Permian	1.05	1.84	(0.79)	(43%)
Eagle Ford	2.07	2.44	(0.37)	(15%)
Total natural gas (per Mcf)	1.27	1.85	(0.58)	(31%)
NGL (per Bbl)				
Permian	11.91	16.58	(4.67)	(28%)
Eagle Ford	11.71	12.69	(0.98)	(8%)
Total NGL (per Bbl)	11.87	15.37	(3.50)	(23%)
Total average realized sales price (per Boe)				
Permian	25.09	44.38	(19.29)	(43%)
Eagle Ford	29.20	49.81	(20.61)	(41%)
Total average realized sales price (per Boe)	$26.45	$44.52	($18.07)	(41%)

	Years Ended December 31,			
	2020	2019 [1]	$ Change	% Change
Average realized sales price (including impact of settled derivatives)				
Oil (per Bbl)	$40.19	$53.31	($13.12)	(25%)
Natural gas (per Mcf)	1.28	2.22	(0.94)	(42%)
NGLs (per Bbl)	11.87	15.37	(3.50)	(23%)
Total average realized sales price (per Boe)	$29.03	$44.27	($15.24)	(34%)
Revenues (in thousands)				
Oil				
Permian	$525,412	$615,235	($89,823)	(15%)
Eagle Ford	325,255	17,872	307,383	1,720%
Total oil	850,667	633,107	217,560	34%
Natural gas				
Permian	33,815	35,818	(2,003)	(6%)
Eagle Ford	18,051	572	17,479	3,056%
Total natural gas	51,866	36,390	15,476	43%
NGLs				
Permian	64,201	1,542	62,659	4,063%
Eagle Ford	17,094	533	16,561	3,107%
Total NGLs	81,295	2,075	79,220	3,818%
Total revenues				
Permian	623,428	652,595	(29,167)	(4%)
Eagle Ford	360,400	18,977	341,423	1,799%
Total revenues	$983,828	$671,572	$312,256	46%
Additional per Boe data				
Lease operating expense				
Permian	$4.71	$6.03	($1.32)	(22%)
Eagle Ford	6.25	8.38	(2.13)	(25%)
Total lease operating expense	$5.22	$6.09	($0.87)	(14%)
Production and ad valorem taxes				
Permian	$1.59	$2.84	($1.25)	(44%)
Eagle Ford	1.87	2.29	(0.42)	(18%)
Total production and ad valorem taxes	$1.68	$2.83	($1.15)	(41%)
Gathering, transportation and processing				
Permian	$2.29	$—	$2.29	100%
Eagle Ford	1.66	—	1.66	100%
Total gathering, transportation and processing	$2.08	$—	$2.08	100%

(1) Includes activity on properties acquired in the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) Effective January 1, 2020, certain of our natural gas processing agreements were modified to allow us to take title to NGLs resulting from the processing of our natural gas. As a result, reserve volumes for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, we presented our reserve volumes for NGLs with natural gas.

(3) Reflects calendar average daily spot market prices.

Revenues

The following table reconciles the changes in oil, natural gas, NGLs, and total revenue for the period presented by reflecting the effect of changes in volume and in the underlying commodity prices.

	Oil	Natural Gas	NGLs	Total
		(In thousands)		
Revenues for the year ended December 31, 2019 (1)(3)	$633,107	$36,390	$2,075	$671,572
Volume increase (decrease)	644,776	38,912	103,212	786,900
Price increase (decrease)	(427,216)	(23,436)	(23,992)	(474,644)
Net increase (decrease)	217,560	15,476	79,220	312,256
Revenues for the year ended December 31, 2020 (2)(3)	$850,667	$51,866	$81,295	$983,828
Percent of total revenues	87 %	5 %	8 %	

(1) Includes activity on properties acquired in the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) Effective January 1, 2020, certain of our natural gas processing agreements were modified to allow us to take title to NGLs resulting from the processing of our natural gas. As a result, reserve volumes for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, we presented our reserve volumes for NGLs with natural gas.

(3) Excludes sales of oil and gas purchased from third parties and sold to our customers.

Commodity Prices

The prices for oil, natural gas, and NGLs remain extremely volatile primarily due to the underlying supply and demand concerns as a result of COVID-19 as well as the actions taken by OPEC and other countries as described above. This volatility was shown in the price of oil which ranged from a low of -$36.98 per Bbl to $63.27 per Bbl. Prices of oil, natural gas, and NGLs will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and cost of the capital;
- the amount we are allowed to borrow under the Credit Facility; and
- the value of our oil and natural gas properties.

Period over Period Variances

The change in absolute value for the year ended December 31, 2020 as compared to the year ended December 31, 2019 can be primarily attributed to the Carrizo Acquisition which closed in December 2019. The Carrizo Acquisition had a material impact to our reported results of operations. In order to provide a more meaningful basis for comparison, we focused our discussion on per unit metrics and only expanded on changes in absolute value where appropriate.

Oil revenue

For the year ended December 31, 2020, oil revenues of $850.7 million increased $217.6 million, or 34%, compared to revenues of $633.1 million for the year ended December 31, 2019. The increase in oil revenue was primarily attributable to a 102% increase in production, partially offset by a 33% decrease in the average realized sales price, which declined to $36.13 per Bbl from $54.27 per Bbl. The increase in production was comprised of 9.5 MMBbls attributable to wells that were acquired in the Carrizo Acquisition and 5.7 MMBbls attributable to wells placed on production as a result of our horizontal drilling program, partially offset by normal and expected declines from our existing wells.

Natural gas revenue

Natural gas revenues increased $15.5 million, or 43%, during the year ended December 31, 2020 to $51.9 million as compared to $36.4 million for the year ended December 31, 2019. The increase primarily relates to an approximate 107% increase in natural gas volumes, partially offset by a 31% decrease in the average price realized, which declined to $1.27 per Mcf from $1.85 per Mcf. The increase in production was comprised of 23.8 Bcf attributable to wells that were acquired in the Carrizo Acquisition and 6.8 Bcf attributable to wells placed on production as a result of our horizontal drilling program, partially offset by normal and expected declines from our existing wells.

NGL revenue

NGL revenues increased $79.2 million during the year ended December 31, 2020 to $81.3 million. The increase was due to certain of our natural gas processing agreements being modified effective January 1, 2020, to allow us to take title to NGLs resulting from the processing of our natural gas. As a result, sales volumes, prices, and revenues for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for sales volumes, prices, and revenues specifically associated with Carrizo, sales and reserve volumes, prices, and revenues for NGLs were presented with natural gas.

Operating Expenses

	Years Ended December 31,							
		Per		Per	Total Change		Boe Change	
	2020	Boe	2019	Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Lease operating expenses	$194,101	$5.22	$91,827	$6.09	$102,274	111%	($0.87)	(14%)
Production and ad valorem taxes	62,638	1.68	42,651	2.83	19,987	47%	(1.15)	(41%)
Gathering, transportation and processing	77,309	2.08	—	—	77,309	100%	2.08	100%
Depreciation, depletion and amortization	480,631	12.92	240,642	15.95	239,989	100%	(3.03)	(19%)
General and administrative	37,187	1.00	45,331	3.00	(8,144)	(18%)	(2.00)	(67%)
Impairment of evaluated oil and gas properties	2,547,241	68.48	—	—	2,547,241	100%	68.48	100%
Merger and integration expenses	28,482	0.77	74,363	4.93	(45,881)	(62%)	(4.16)	(84%)

Lease operating expenses. These are daily costs incurred to extract oil and natural gas and maintain our producing properties. Such costs also include maintenance, repairs, gas treating fees, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

Lease operating expenses for the year ended December 31, 2020 increased by 111% to $194.1 million compared to $91.8 million for the same period of 2019, primarily due to production volumes increasing 147%. Lease operating expense per Boe for the year ended December 31, 2020 decreased to $5.22 compared to $6.09 for the same period of 2019 primarily due to continuing improvement of managing our field operating costs during the integration of the properties acquired from Carrizo as well as lower repairs and maintenance activities and workover expenses.

Production and valorem taxes. In general, severance taxes are based upon current year commodity prices whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. We benefit from tax credits and exemptions in our various taxing jurisdictions where available and applicable. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

For the year ended December 31, 2020, production and ad valorem taxes increased 47% to $62.6 million compared to $42.7 million for the same period in 2019, which is primarily related to a 46% increase in total revenues which increased production taxes and the inclusion of the properties from the Carrizo Acquisition in the property valuations for ad valorem taxes. Production and ad valorem taxes as a percentage of total revenues remained consistent for the year ended December 31, 2020 as compared to the year ended December 31, 2019 at 6.4%. Although production taxes as a percentage of total revenues decreased from the year ended December 31, 2019 due to the contribution of the Carrizo Acquisition assets which carried lower effective production tax rates as a result of the impacts of natural gas and NGL marketing deductions and exemptions, this was offset by an increase in ad valorem tax as a percentage of revenue during the year ended December 31, 2020 due to the timing of the property tax valuations compared to the significant decrease in the price of crude oil affecting our revenues during 2020.

Gathering, transportation and processing expenses. Gathering, transportation and processing costs for the year ended December 31, 2020 were $77.3 million. No expense was recognized for gathering, transportation and processing costs during the same period of 2019. The change is due to the assumption of the processing agreements assumed in the Carrizo Acquisition and certain contract modifications effective January 1, 2020. As such, the Company now records contractual fees associated with gathering, processing, treating and compression, as well as any transportation fees incurred to deliver the product to the purchaser, as gathering, transportation and processing expense. These fees were historically recorded as a reduction of revenue depending on when control transferred to the purchaser.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically amortize those costs on an equivalent unit-of-production method based on production and estimated proved oil and gas reserve quantities. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from two to twenty years. The following table sets forth the components of our depreciation, depletion and amortization for the periods indicated:

	Years Ended December 31,			
	2020		2019	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per Boe)			
DD&A of evaluated oil and gas properties	$471,074	$12.66	$239,679	$15.89
Depreciation of other property and equipment	3,548	0.10	18	—
Amortization of other assets	2,686	0.07	—	—
Accretion of asset retirement obligations	3,323	0.09	945	0.06
DD&A	$480,631	$12.92	$240,642	$15.95

For the year ended December 31, 2020, DD&A increased 100% to $480.6 million from $240.6 million compared to the same period of 2019. The additional DD&A was primarily related to an increase in DD&A of evaluated oil and gas properties, which was primarily attributable to a 147% increase in production, as discussed above, partially offset by lower DD&A rates between the periods. For the year ended December 31, 2020, DD&A per Boe decreased to $12.92 compared to $15.95 for the same period of 2019 primarily as a result of the impairments of evaluated oil and gas properties that were recognized during 2020 as well as the Carrizo Acquisition which contributed to an increase in our proved reserves at a lower relative cost per Boe than our historical DD&A rate.

General and administrative, net of amounts capitalized ("G&A"). G&A for the year ended December 31, 2020 decreased to $37.2 million compared to $45.3 million for the same period of 2019, primarily due to cost saving initiatives and a decrease in the fair value of the cash-settled restricted stock units and cash-settled stock appreciation rights partially offset by increased headcount of the combined companies.

Impairment of evaluated oil and gas properties. We recognized an impairment of evaluated oil and gas properties of $2.5 billion for the year ended December 31, 2020, due primarily to declines in the 12-Month Average Realized Price of crude oil of 31%. There was no impairment of evaluated oil and gas properties for the year ended December 31, 2019. See "Note 5 - Property and Equipment, Net" of the Notes to our Consolidated Financial Statements for further discussion.

Merger and integration expense. For the year ended December 31, 2020, the Company incurred expenses associated with the Carrizo Acquisition of $28.5 million as compared to $74.4 million for the same period of 2019. See "Note 4 – Acquisitions and Divestitures" of the Notes to our Consolidated Financial Statements for additional information regarding the Carrizo Acquisition.

Other Income and Expenses

	Years Ended December 31,			
	2020	2019	$ Change	% Change
	(In thousands, except % amounts)			
Interest expense	$182,928	$81,399	$101,529	125%
Capitalized interest	(88,599)	(78,492)	(10,107)	13%
Interest expense, net of capitalized amounts	94,329	2,907	91,422	3,145%
(Gain) loss on derivative contracts	27,773	62,109	(34,336)	(55%)
(Gain) loss on extinguishment of debt	(170,370)	4,881	(175,251)	(3,590%)

Interest expense, net of capitalized amounts. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense. The following table sets forth the components of our interest expense, net of capitalized amounts for the periods indicated:

	Years Ended December 31,		
	2020	2019	Change
		(In thousands)	
Interest expense on Credit Facility	$45,912	$14,422	$31,490
Interest expense on Second Lien Notes	9,188	—	9,188
Interest expense on Senior Notes	120,313	64,061	56,252
Amortization of debt issuance costs, premiums, and discounts	7,325	2,902	4,423
Other interest expense	190	14	176
Capitalized interest	(88,599)	(78,492)	(10,107)
Interest expense, net of capitalized amounts	$94,329	$2,907	$91,422

Interest expense, net of capitalized amounts, incurred during the year ended December 31, 2020 increased $91.4 million to $94.3 million compared to $2.9 million for the same period of 2019. The increase is primarily due to debt that was assumed as a result of the Carrizo Acquisition and the issuance of the Second Lien Notes during 2020 partially offset by an increase in capitalized interest as a result of an increase in the balance of unevaluated properties as a result of the Carrizo Acquisition.

(Gain) loss on derivative contracts. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. This amount represents the (i) (gain) loss related to fair value adjustments on our open derivative contracts and (ii) (gains) losses on settlements of derivative contracts for positions that have settled within the period. The net (gain) loss on derivative contracts for the periods indicated includes the following:

	Years Ended December 31,		
	2020	2019	Change
		(In thousands)	
(Gain) loss on oil derivatives	($48,031)	$73,313	($121,344)
(Gain) loss on natural gas derivatives	14,883	(8,889)	23,772
(Gain) loss on NGL derivatives	2,426	—	2,426
(Gain) loss on contingent consideration arrangements	2,976	(2,315)	5,291
(Gain) loss on September 2020 Warrants liability	55,519	—	55,519
(Gain) loss on derivative contracts	$27,773	$62,109	($34,336)

See “Note 8 - Derivative Instruments and Hedging Activities” and “Note 9 - Fair Value Measurements” of the Notes to our Consolidated Financial Statements for additional information.

(Gain) loss on extinguishment of debt. During November 2020, in connection with the exchange of $389.0 million of our Senior Unsecured Notes for the November 2020 Second Lien Notes, we recorded a gain on extinguishment of debt of $170.4 million, which consisted of the carrying values of the Senior Unsecured Notes exchanged less the aggregate principal amount of the November 2020 Second Lien Notes issued, net of the associated debt discount of $9.1 million, which was based on the November 2020 Second Lien Notes’ allocated fair value on the exchange date. During December 2019, in connection with the Carrizo Acquisition, we entered into a new credit facility and simultaneously terminated our prior credit facility. As a result of terminating the prior credit facility, we recorded a loss on extinguishment of debt of $4.9 million, which was comprised solely of the write-off of unamortized deferred financing costs associated with the prior credit facility. See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information.

Sales and cost of purchased oil and gas. For the year ended December 31, 2020, we recorded sales of purchased oil and gas of $49.3 million and cost of purchased oil and gas of $51.8 million related to commodities purchased from third parties and sold to our customers. No sales or cost of purchased oil and gas occurred during the same periods of 2019.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate, based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

We recorded income tax expense of $122.1 million for the year ended December 31, 2020 compared to $35.3 million for the same period of 2019. The increase in income tax expense is due to the recording of a valuation allowance during the year ended

December 31, 2020. See "Note 12 – Income Taxes" of the Notes to our Consolidated Financial Statements for additional information regarding the valuation allowance.

Preferred stock dividends. On July 18, 2019, we redeemed all outstanding shares of Preferred Stock, after which, the Preferred Stock was no longer deemed outstanding and dividends ceased to accrue. As such, we did not make any Preferred Stock dividend payments during the year ended December 31, 2020. Preferred Stock dividends of $4.0 million were paid during the year ended December, 31, 2019. See "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional information.

Loss on redemption of preferred stock. As a result of the redemption of our Preferred Stock mentioned above, we recognized an $8.3 million loss due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value during 2019. See "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional information.

Liquidity and Capital Resources

2021 Capital Budget and Funding Strategy. Our primary uses of capital are for the exploration and development of our oil and natural gas properties. Our 2021 Capital Budget has been established at up to $430.0 million, with approximately 80% directed towards drilling, completion, and equipment expenditures. Our scaled development plan for 2021 will continue to employ our life of field development philosophy and benefit from our balanced capital deployment strategy. The 2021 Capital Budget leverages the structural savings and operational efficiencies achieved during 2020 from shared best practices following the integration of Callon and Carrizo. Approximately 70% of the 2021 Capital Budget is allocated towards development in the Permian with the remaining 30% towards development in the Eagle Ford. As part of our 2021 operated horizontal drilling program, we expect to drill approximately 55 to 65 gross operated wells and complete approximately 90 to 100 gross operated wells.

Because we are the operator of a high percentage of our properties, we can control the amount and timing of our capital expenditures. We can choose to defer or accelerate a portion of our planned capital expenditures depending on various factors, including, but not limited to, continued depressed commodity prices, market conditions, our available liquidity and financing, acquisitions and divestitures of oil and gas properties, the availability of drilling rigs and completion crews, the cost of completion services, success of drilling programs, land and industry partner issues, weather delays, the acquisition of leases with drilling commitments, and other factors. We plan to execute a more moderated capital expenditure program through reduced reinvestment rates and balanced capital deployment for a more consistent cash flow generation and will be focused to further enhance our multi-zone, scale development program while leveraging a robust drilled, but uncompleted backlog to drive capital efficiency.

The following table is a summary of our 2020 capital expenditures [(1)]:

	Three Months Ended				Year Ended
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020	December 31, 2020
			(In millions)		
Operational capital	$277.6	$85.1	$38.4	$87.5	$488.6
Capitalized interest	24.0	20.9	20.7	23.0	88.6
Capitalized G&A	7.4	8.9	10.2	8.9	35.4
Total	$309.0	$114.9	$69.3	$119.4	$612.6

(1) Capital expenditures, presented on an accrual basis, includes facilities, equipment, seismic, and land, but excludes asset retirement costs.

We continually evaluate our capital expenditure needs and compare them to our capital resources. Due to the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment, we reduced our development plan in order to preserve capital, including the temporary cessation of all drilling and completion activities for most of the second and third quarters of 2020. We reactivated two completion crews, one each in the Eagle Ford and Permian, both of which completed previously drilled multi-well projects during September. Subsequently, one of the two completion crews was released and three drilling rigs resumed operations, two restarting operations in the Permian during September and the third reactivated in the Eagle Ford during October. This reduction in activity resulted in our actual 2020 operational capital expenditures to be approximately 50% of our original operational capital budget for 2020 of $975.0 million.

Historically, our primary sources of capital have been cash flows from operations, borrowings under our revolving credit facility, proceeds from the issuance of debt securities and public equity offerings, and non-core asset dispositions. We regularly consider which resources, including debt and equity financings, are available to meet our future financial obligations, planned capital expenditures and liquidity requirements. In addition, depending upon our actual and anticipated sources and uses of liquidity, prevailing market conditions and other factors, we may, from time to time, seek to retire or repurchase our outstanding debt or equity securities through cash purchases in the open market or through privately negotiated transactions or otherwise. The amounts involved in any such transactions, individually or in aggregate, may be material. During 2020, to help manage our future financing cash outflows and liquidity position, we completed the exchange of $389.0 million of aggregate principal amount of our existing Senior Unsecured Notes for $216.7 million aggregate principal amount of November 2020 Second Lien Notes and 1.75 million November 2020 Warrants. This exchange resulted in the removal of approximately $172.3 million from the long-term debt balance in our consolidated balance sheets and also reduced future interest payments.

We may consider divesting certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth or enter into joint venture agreements, provided we are able to divest such assets or enter into joint venture agreements on terms that are acceptable to us. During 2020, we entered into the ORRI Transaction and sold substantially all of our non-operated assets for combined net proceeds of $165.4 million, which were used to repay borrowings outstanding under the Credit Facility.

Overview of Cash Flow Activities. For the year ended December 31, 2020, cash and cash equivalents increased $6.9 million to $20.2 million compared to $13.3 million at December 31, 2019.

	Years Ended December 31,	
	2020	**2019** [(1)]
	(In thousands)	
Net cash provided by operating activities	$559,775	$476,316
Net cash used in investing activities	(529,883)	(388,389)
Net cash used in financing activities	(22,997)	(90,637)
Net change in cash and cash equivalents	$6,895	($2,710)

(1) Includes activity on properties acquired in the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

Operating activities. Net cash provided by operating activities was $559.8 million and $476.3 million for the years ended December 31, 2020 and 2019, respectively. The increase in operating activities was predominantly attributable to the following:

- An increase in revenue due to higher production volumes, offset by a decrease in realized pricing;
- A decrease in merger and integration expenses;
- An offsetting increase in operating expenses as a result of higher production volumes; and
- Changes related to timing of working capital payments and receipts.

Production, realized prices, and operating expenses are discussed above in Results of Operations. See "Note 8 – Derivative Instruments and Hedging Activities" and "Note 9 – Fair Value Measurements" of the Notes to our Consolidated Financial Statements for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. Net cash used in investing activities was $529.9 million and $388.4 million for the years ended December 31, 2020 and 2019, respectively. The increase in investing activities was primarily attributable to the following:

- A decrease in proceeds from sales of assets to $179.5 million during the year ended December 31, 2020, which were primarily associated with the ORRI Transaction and the sale of substantially all of our non-operated assets, compared to proceeds from sales of assets of $294.4 million for the year ended December 31, 2019;
- Partially offset by a $42.3 million decrease in acquisitions; and
- Net cash payments of $40.0 million associated with contingent considerations arrangements acquired in the Carrizo Acquisition that were paid in January 2020.

Financing activities. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under the Credit Facility, term debt and equity offerings. For the year ended December 31, 2020, net cash used in financing activities was $23.0 million compared to net cash used in financing activities of $90.6 million during 2019. The decrease in net cash used in financing activities was primarily attributable to the following:

- Issuance of the September 2020 Second Lien Notes and September 2020 Warrants for net proceeds of approximately $288.6 million;
- Repayment of approximately $300.0 million on the Credit Facility during 2020;
- Repayment of Carrizo's credit facility and funding the redemption of preferred stock upon closing the Carrizo Acquisition in 2019; and
- Redemption of Preferred Stock for approximately $73.0 million in 2019.

See "Note 7 – Borrowings", "Note 10 – Share-Based Compensation", and "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional information regarding our debt and equity transactions.

Credit Facility. On December 20, 2019, upon consummation of the Merger, we entered into the Credit Facility which provides for interest-only payments until December 20, 2024 (subject to springing maturity dates of (i) January 14, 2023 if the 6.25% Senior Notes are outstanding at such time, (ii) July 2, 2024 if the 6.125% Senior Notes are outstanding at such time, and (iii) if the Second Lien

Notes are outstanding at such time, the date which is 182 days prior to the maturity of any of the 6.25% Senior Notes or the 6.125% Senior Notes, in each case, to the extent a principal amount of more than $100.0 million with respect to each such issuance is outstanding as of such date), when the Credit Facility matures and any outstanding borrowings are due. The maximum credit amount under the Credit Facility is $5.0 billion. The borrowing base under the credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering our major producing properties. As of December 31, 2020, the borrowing base and elected commitment amount under the revolving credit facility was $1.6 billion, with borrowings outstanding of $985.0 million at a weighted average interest rate of 2.73%, and letters of credit outstanding of $25.2 million.

Our Credit Facility contains certain covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. Under the Credit Facility, we must maintain the following financial covenants determined as of the last day of the quarter, each as described above: (1) a Secured Leverage Ratio of no more than 3.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. We were in compliance with these covenants at December 31, 2020.

The Credit Facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information including details of the first, second, and third amendments to the Credit Facility.

Second Lien Notes. On September 30, 2020, we issued $300.0 million in aggregate principal amount of our September 2020 Second Lien Notes and 7.3 million September 2020 Warrants for aggregate consideration of $294.0 million. The Company used the proceeds, net of issuance costs, of approximately $288.6 million to repay borrowings outstanding under the Credit Facility. See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information.

Senior Unsecured Notes Exchange. On November 13, 2020, we closed on the exchange of $389.0 million of aggregate principal amount of the Senior Unsecured Notes for $216.7 million aggregate principal amount of November 2020 Second Lien Notes at a weighted average exchange ratio of approximately $557 per $1,000 of principal exchanged and approximately 1.75 million November 2020 Warrants. As a result of the exchange, we recognized a gain on extinguishment of debt of $170.4 million in our consolidated statement of operations, which consisted of the carrying values of the Senior Unsecured Notes exchanged less the aggregate principal amount of the November 2020 Second Lien Notes issued, net of the associated debt discount of $9.1 million, which was based on the November 2020 Second Lien Notes’ allocated fair value on the exchange date. See “Note 7 - Borrowings” of the Notes to our Consolidated Financial Statements for additional information about the exchange.

Even considering the downturn in commodity prices as well as a drop in demand as a result of COVID-19, we expect to have sufficient liquidity to pay interest on our Credit Facility, Second Lien Notes, and Senior Unsecured Notes as well as to fund our development program. Upon a redetermination, if any borrowings in excess of the revised borrowing base were outstanding, we could be forced to immediately repay a portion of the borrowings outstanding under the credit agreement. Additionally, if a low commodity price environment were to persist for an extended period, our ability to remain in compliance with our restrictive financial covenants in our Credit Facility and our indentures could be challenged. If we are unable to remain in compliance with our restrictive financial covenants, we could be subject to lender elections for default resolution.

Hedging. As of February 19, 2021, we had the following outstanding oil, natural gas and NGL derivative contracts:

Oil contracts (WTI)	For the Full Year of 2021		For the Full Year of 2022	
Swap contracts				
Total volume (Bbls)	1,827,000		—	
Weighted average price per Bbl	$43.54		$—	
Collar contracts				
Total volume (Bbls)	11,202,775		1,355,000	
Weighted average price per Bbl				
Ceiling (short call)	$47.80		$60.00	
Floor (long put)	$39.95		$45.00	
Short call contracts				
Total volume (Bbls)	4,825,300	(1)	—	
Weighted average price per Bbl	$63.62		$—	
Short call swaption contracts				
Total volume (Bbls)	455,000	(2)	1,825,000	(2)
Weighted average price per Bbl	$47.00		$52.18	
Oil contracts (ICE Brent)				
Swap contracts				
Total volume (Bbls)	505,000	(3)	—	
Weighted average price per Bbl	$37.34		$—	
Collar contracts				
Total volume (Bbls)	730,000		—	
Weighted average price per Bbl				
Ceiling (short call)	$50.00		$—	
Floor (long put)	$45.00		$—	
Oil contracts (Midland basis differential)				
Swap contracts				
Total volume (Bbls)	3,022,900		—	
Weighted average price per Bbl	$0.26		$—	
Oil contracts (Argus Houston MEH)				
Swap contracts				
Total volume (Bbls)	450,000		—	
Weighted average price per Bbl	$46.50		$—	
Collar contracts				
Total volume (Bbls)	409,500		—	
Weighted average price per Bbl				
Ceiling (short call)	$47.00		$—	
Floor (long put)	$41.00		$—	

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

(2) The short call swaption contracts have exercise expiration dates as follows: 455,000 Bbls expire on March 31, 2021 and 1,825,000 Bbls expire on December 31, 2021.

(3) In January 2021, we paid approximately $3.1 million to terminate 184,000 Bbls of ICE Brent swaps. Additionally, in February 2021, we executed offsetting ICE Brent swaps on 159,300 Bbls, resulting in a locked-in loss of approximately $2.9 million which we will pay as the applicable contracts settle.

Natural gas contracts (Henry Hub)	For the Full Year of 2021		For the Full Year of 2022
Swap contracts			
Total volume (MMBtu)	11,123,000		—
Weighted average price per MMBtu	$2.60		$—
Collar contracts (three-way collars)			
Total volume (MMBtu)	1,350,000		—
Weighted average price per MMBtu			
Ceiling (short call)	$2.70		$—
Floor (long put)	$2.42		$—
Floor (short put)	$2.00		$—
Collar contracts (two-way collars)			
Total volume (MMBtu)	9,550,000		1,800,000
Weighted average price per MMBtu			
Ceiling (short call)	$3.04		$3.88
Floor (long put)	$2.59		$2.78
Short call contracts			
Total volume (MMBtu)	7,300,000	(1)	—
Weighted average price per MMBtu	$3.09		$—
Natural gas contracts (Waha basis differential)			
Swap contracts			
Total volume (MMBtu)	16,425,000		—
Weighted average price per MMBtu	($0.42)		$—

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

NGL contracts (OPIS Mont Belvieu Purity Ethane)	For the Full Year of 2021
Swap contracts	
Total volume (Bbls)	1,825,000
Weighted average price per Bbl	$7.62

Preferred Stock. On June 18, 2019, we announced we had given notice for the redemption (the "Redemption") of all outstanding shares of the Preferred Stock. On July 18, 2019 (the "Redemption Date"), the Preferred Stock were redeemed at a redemption price equal to $50.00 per share, plus an amount equal to all accrued and unpaid dividends in an amount equal to $0.24 per share, for a total redemption price of $50.24 per share or $73.0 million (the "Redemption Price"). We recognized an $8.3 million loss on the redemption due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value of the Preferred Stock. After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest. We paid $4.0 million for Preferred Stock dividends for the year ended December 31, 2019. See "Note 11 - Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional discussion.

Contractual Obligations

The following table includes our current contractual obligations and purchase commitments as of December 31, 2020:

	Payments due by Period				
	< 1 Year	Years 2 - 3	Years 4 - 5	> 5 Years	Total
			(In thousands)		
Credit Facility [1]	$—	$—	$985,000	$—	$985,000
9.00% Second Lien Senior Secured Notes [2]	—	—	516,659	—	516,659
6.25% Senior Notes [2]	—	542,720	—	—	542,720
6.125% Senior Notes [2]	—	—	460,241	—	460,241
8.25% Senior Notes [2]	—	—	187,238	—	187,238
6.375% Senior Notes [2]	—	—	—	320,783	320,783
Interest expense and other fees related to debt commitments [3]	174,387	331,815	198,714	20,450	725,366
Drilling rig leases [4]	4,317	—	—	—	4,317
Operating leases [5]	10,601	10,454	8,894	14,139	44,088
Delivery commitments [6]	12,401	22,533	24,868	39,291	99,093
Produced water disposal commitments [7]	21,355	29,095	12,242	741	63,433
Asset retirement obligations [8]	1,881	587	6,827	49,795	59,090
Total contractual obligations	$224,942	$937,204	$2,400,683	$445,199	$4,008,028

(1) The Credit Facility has a maturity date of December 20, 2024, subject to springing maturity dates as discussed above. See "Note 7 – Borrowings" of the Notes to our Consolidated Financial Statements for additional information.

(2) Includes the outstanding principal amount only.

(3) Includes estimated cash payments on the 9.00% Second Lien Senior Secured Notes, 6.25% Senior Notes, 6.125% Senior Notes, 8.25% Senior Notes, 6.375% Senior Notes, the Credit Facility and commitment fees calculated based on the unused portion of lender commitments as of December 31, 2020, at the applicable commitment fee rate.

(4) Drilling rig leases represent future minimum expenditure commitments for drilling rig services under contracts to which the Company was a party on December 31, 2020. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. In January 2021, we extended one of our drilling rig contracts for a term of one year. The gross contractual obligation for this extended drilling rig contract is approximately $5.5 million and is not included in the table above as it was entered into subsequent to December 31, 2020. See "Note 17 – Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for additional information related to our drilling rig leases.

(5) Operating leases primarily consist of contracts for office space. See "Note 13 – Leases" of the Notes to our Consolidated Financial Statements for additional information.

(6) Delivery commitments represent contractual obligations we have entered into for certain gathering, processing and transportation service agreements which require minimum volumes of oil or natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any oil or natural gas.

(7) Produced water disposal commitments represent contractual obligations we have entered into for certain service agreements which require minimum volumes of produced water to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water.

(8) Amounts represent our estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See "Note 14 – Asset Retirement Obligations" of the Notes to our Consolidated Financial Statements for additional information.

Other commitments

The following table includes our current oil sales contracts and firm transportation agreements as of December 31, 2020:

Type of Commitment [1]	Region	Execution Date	Start Date	End Date	Committed Volumes (Bbls/d)
Oil sales contract	Eagle Ford	November 2020	January 2021	December 2021	10,000
Oil sales contract	Permian	August 2020	August 2020	December 2021	7,500
Oil sales contract	Permian	July 2019	August 2021	July 2026	5,000
Oil sales contract	Permian	June 2019	January 2020	December 2024	10,000
Oil sales contract	Permian	August 2018	April 2020	March 2022	15,000
Firm transportation agreement [2][3]	Permian	June 2019	August 2020	July 2030	10,000
Firm transportation agreement [2]	Permian	August 2018	April 2020	March 2027	15,000

(1) For each of the commitments shown in the table above, the committed barrels may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf. We expect to fulfill these delivery commitments with our existing production or through the purchases of third-party commodities.

(2) Each of the firm transportation agreements shown in the table above grant us access to delivery points in several locations along the Gulf Coast.

(3) The committed volumes shown in the table above for this particular firm transportation agreement are average volumes. For the terms of August 2020-July 2023, August 2023-July 2027 and August 2027-July 2030, the committed volumes are 7,500 Bbls/d, 10,000 Bbls/d and 12,500 Bbls/d, respectively.

Summary of Critical Accounting Policies

The following summarizes our critical accounting policies. See a complete list of significant accounting policies in “Note 2 – Summary of Significant Accounting Policies” of the Notes to our Consolidated Financial Statements.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make judgments affecting estimates and assumptions for reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Estimates of proved oil and gas reserves are used in calculating DD&A of evaluated oil and natural gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated timing of cash outflows underlying asset retirement obligations. There are numerous uncertainties inherent in the estimation of proved oil and gas reserves and in the projection of future rates of production and the timing of development expenditures. Other significant estimates are involved in determining asset retirement obligations, acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of commodity derivative assets and liabilities, fair values of contingent consideration arrangements, grant date fair value of stock-based awards, and contingency, litigation, and environmental liabilities. Actual results could differ from those estimates.

Oil and natural gas properties

Oil and natural gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized as oil and gas properties. The internal cost of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized to either evaluated or unevaluated oil and gas properties based on the type of activity. Internal costs related to production and similar activities are expensed as incurred.

Proceeds from the sale or disposition of evaluated and unevaluated oil and gas properties are accounted for as a reduction of evaluated oil and gas property costs, unless the sale significantly alters the relationship between capitalized costs and estimated proved reserves in which case a gain or loss is recognized. For the years ended December 31, 2020, 2019, and 2018, we did not have any sales of oil and gas properties that significantly altered such relationship.

Capitalized oil and gas property costs are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production depletion rate is computed on a quarterly basis by dividing current quarter production by estimated proved oil and gas reserves at the beginning of the quarter then applying such depletion rate to evaluated oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus estimated future expenditures to be incurred in developing proved reserves, net of estimated salvage values.

Excluded from this amortization are costs associated with unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or we determine that these costs have been impaired. We assess properties on an individual basis or as a group and consider the following factors, among others, to determine if these costs have been impaired: exploration program and intent to drill, remaining lease term, and the assignment of proved reserves. As a result of the downturn in the oil and gas industry as well as in the broader macroeconomic environment in 2020, we analyzed our unevaluated leasehold giving consideration to our updated exploration program as well as to the remaining lease term of certain unevaluated leaseholds. As a result, we impaired $229.6 million unevaluated leasehold costs and transferred these costs to evaluated properties during the year ended December 31, 2020.

Geological and geophysical costs not associated with specific prospects are recorded to evaluated oil and gas property costs as incurred. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unevaluated properties and the weighted average interest rate of outstanding borrowings. Capitalized interest cannot exceed gross interest expense.

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from estimated proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the estimated proved reserves computed using a discount factor of 10%, (b) the costs of unevaluated properties not being amortized, and (c) the lower of cost or estimated fair value of unevaluated properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of evaluated oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of oil, NGLs, and natural gas on the first calendar day of each month during the 12-month period prior to the end of the quarter (the "12-Month Average Realized Price"), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of commodity derivative instruments as we elected not to meet the criteria to qualify for hedge accounting treatment.

Primarily as a result of the significant reduction in the 12-Month Average Realized Price of oil, we recognized impairments of evaluated oil and gas properties of $2.5 billion for the year December 31, 2020. We did not recognize impairments of evaluated oil and gas properties for the years ended December 31, 2019 and 2018. Details of the 12-Month Average Realized Price of crude oil for the years ended December 31, 2020, 2019, and 2018 are summarized in the table below:

	Years Ended December 31,		
	2020	**2019**	**2018**
Impairment of evaluated oil and natural gas properties (In thousands)	$2,547,241	$—	$—
Beginning of period 12-Month Average Realized Price ($/Bbl)	$53.90	$58.40	$49.48
End of period 12-Month Average Realized Price ($/Bbl)	$37.44	$53.90	$58.40
Percent increase (decrease) in 12-Month Average Realized Price	(31%)	(8%)	18%

The decrease in the 12-Month Average Realized Price as of December 31, 2020 reduced our proved oil and gas reserve volumes by approximately 26.2 MMBoe. This reduction was primarily attributable to proved developed reserves of producing wells and proved undeveloped reserves with shorter economic lives. Volumes associated with locations of proved undeveloped reserves that were no longer economic and removed from proved reserves as a result of the decrease in the 12-Month Average Realized Price as of December 31, 2020 were less than 1.0 MMBoe.

Our current forecast for the first quarter of 2021 includes the following:

- Estimated 12-Month Average Realized Price based on the first calendar day of each month oil and gas prices available for the 11 months ended February 1, 2021 and an estimate for the twelfth month based on a quoted forward price;
- Estimated range of the first quarter of 2021 cost center ceiling, at the high end, that would exceed the net book value of oil and gas properties, resulting in no impairment in the carrying value of evaluated oil and gas properties, and at the low end, would result in an impairment in the carrying value of evaluated oil and gas properties of $100.0 million;
- No proved undeveloped reserves that would no longer be economic and would be removed from proved reserves as of March 31, 2021; and
- Assumes that all other inputs and assumptions are as of December 31, 2020, other than the price of crude oil, natural gas, and NGLs, and remain unchanged.

Drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, and changes in development and operating costs occurring subsequent to December 31, 2020 may require revisions to estimates of proved reserves, which would impact the calculation of the cost center ceiling described above. Further impairments in subsequent quarters may occur if the trailing

12-month commodity prices continue to be lower than the comparable trailing 12-month commodity prices applicable to 2020. Based on the current outlook for future commodity prices, we do not believe that those prices, if realized, would have a significant adverse impact on our proved oil and gas reserves volumes.

In addition, the process of estimating proved oil and gas reserves requires that the Company's independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and natural gas prices under Part I, "Item 1A. Risk Factors."

The table below presents various pricing scenarios to demonstrate the sensitivity of our December 31, 2020 cost center ceiling to changes in 12-month average benchmark crude oil and natural gas prices underlying the 12-Month Average Realized Prices. The sensitivity analysis is as of December 31, 2020 and, accordingly, does not consider drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, changes in crude oil and natural gas prices, and changes in development and operating costs occurring subsequent to December 31, 2020 that may require revisions to estimates of proved reserves. See also Part I, "Item 1A. Risk Factors—If oil and natural gas prices remain depressed for extended periods of time, we may be required to make significant downward adjustments to the carrying value of our oil and natural gas properties."

	12-Month Average Realized Prices		Excess (deficit) of cost center ceiling over net book value, less related deferred income taxes	Increase (decrease) of cost center ceiling over net book value, less related deferred income taxes
Full Cost Pool Scenarios	**Crude Oil ($/Bbl)**	**Natural Gas ($/Mcf)**	**(In millions)**	**(In millions)**
December 31, 2020 Actual	$37.44	$1.02	$—	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$41.40	$1.21	$640	$640
Crude Oil and Natural Gas -10%	$33.49	$0.81	($632)	($632)
Crude Oil Price Sensitivity				
Crude Oil +10%	$41.40	$1.02	$602	$602
Crude Oil -10%	$33.49	$1.02	($588)	($588)
Natural Gas Price Sensitivity				
Natural Gas +10%	$37.44	$1.21	$48	$48
Natural Gas -10%	$37.44	$0.81	($50)	($50)

Asset retirement obligations

We record an estimate of the fair value of liabilities for obligations associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Estimates involved in determining asset retirement obligations include the future plugging and abandonment costs of wells and related facilities, the ultimate productive life of the properties, a credit-adjusted risk-free discount rate and an inflation factor in order to determine the present value of the asset retirement obligation. The present value of the asset retirement obligations is accreted each period and the increase to the obligations is reported in "Depreciation, depletion and amortization" in the consolidated statements of operations. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to evaluated oil and gas properties in the consolidated balance sheets. See "Note 14 - Asset Retirement Obligations" of the Notes to our Consolidated Financial Statements for additional information.

Estimating the future plugging and abandonment costs of wells and related facilities requires management to make estimates and judgments because most of the obligations are many years in the future and asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Derivative instruments

We use commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of our forecasted sales of production and achieve a more predictable level of cash flow. We do not use these instruments for speculative or trading purposes. Settlements of derivative contracts are generally based on the difference between the contract price and prices specified in the derivative instrument and a NYMEX price or other futures index price.

Our commodity derivative instruments, as well as our contingent consideration arrangements, are carried at their fair value in the consolidated balance sheets with all gains and losses as a result of changes in the fair value recognized in the consolidated statements of operations in the period in which the changes occur. The estimated fair value of our derivative contracts is based upon current forward market prices on NYMEX and in the case of collars and floors, the time value of options. For additional information regarding our derivatives instruments and their fair values, see "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" of the Notes to our Consolidated Financial Statements and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk".

Income taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards.

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that our net deferred tax assets will be utilized prior to their expiration. A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at December 31, 2020, driven primarily by impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the end of the year, which limits the ability to consider other subjective evidence such as our potential for future growth. Beginning in the second quarter of 2020 and continuing through the end of 2020, based on the evaluation of the evidence available, we concluded that it is more likely than not that the net deferred tax assets will not be realized. As a result, we recorded a valuation allowance of $639.2 million, reducing the net deferred tax assets as of December 31, 2020 to zero.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income. As long as we continue to conclude that the valuation allowance against our net deferred tax assets is necessary, we will have no significant deferred income tax expense or benefit. See "Note 12 - Income Taxes" of the Notes to our Consolidated Financial Statements for additional discussion.

Our ability to utilize our federal net operating losses ("NOLs") to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of stock by 5% shareholders and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Callon. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of Callon multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold. Due to the issuance of common stock associated with the Carrizo Acquisition, we incurred a cumulative ownership change and as such, our NOLs prior to the acquisition are subject to an annual limitation under Internal Revenue Code Section 382.

Recently Adopted and Recently Issued Accounting Pronouncements

See "Note 2 - Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements for information discussion of recent accounting pronouncements issued by the Financial Accounting Standards Board.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2020.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer credit risk. We mitigate these risks through a program of risk management including the use of commodity derivative instruments.

Commodity price risk

Our revenues are derived from the sale of our oil, natural gas, and NGL production. The prices for oil, natural gas, and NGLs remain extremely volatile primarily due to the underlying supply and demand concerns as a result of COVID-19 as well as the actions taken by OPEC and other countries as described above. This volatility was shown in the price of oil which ranged from a low of -$36.98 per Bbl to $63.27 per Bbl.

The following table sets forth oil, natural gas and NGL revenues for the year ended December 31, 2020 as well as the impact on the oil, natural gas and NGL revenues assuming a 10% increase or decrease in our average realized sales prices for oil, natural gas and NGLs, excluding the impact of commodity derivative settlements:

	Year Ended December 31, 2020			
	Oil	Natural Gas	NGLs	Total
		(In thousands)		
Revenues	$850,667	$51,866	$81,295	$983,828
Impact of a 10% fluctuation in average realized prices	$85,067	$5,187	$8,129	$98,383

From time to time, we enter into derivative financial instruments to manage oil, natural gas and NGL price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes we hedge through use of our derivative instruments varies from period to period. Generally, our objective is to hedge approximately 60% of our anticipated internally forecasted production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices.

As of December 31, 2020, for the full year of 2021, we had 14,547,575 Bbls of fixed price oil hedges across NYMEX WTI, ICE Brent and Argus WTI-Houston benchmarks. We also had 3,022,900 Bbls of WTI Midland-Cushing oil basis hedges. Additionally, for the full year of 2021, we had 22,023,000 MMBtus of fixed price NYMEX natural gas hedges and 16,425,000 MMBtus of Waha natural gas basis hedges. See “Note 8 - Derivative Instruments and Hedging Activities” of the Notes to our Consolidated Financial Statements for a description of our outstanding derivative contracts as of December 31, 2020.

We may utilize fixed price swaps, which reduce our exposure to decreases in commodity prices, but limits the benefit we might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales.

We also may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counterparty to the collar pays the difference to us, and if the price rises above the ceiling, the counterparty receives the difference from us. Additionally, we may sell put options at a price lower than the floor price in conjunction with a collar (three-way collar) and use the proceeds to increase either/both the floor or ceiling prices. In a three-way collar, to the extent that realized prices are below the floor price of the sold put option (or above the ceiling price of the sold call option), our net realized benefit from the three-way collar will be reduced on a dollar-for-dollar basis.

We may purchase put options, which reduce our exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to us.

We enter into these various agreements from time to time to reduce the effects of volatile oil, natural gas and NGL prices and do not enter into derivative transactions for speculative or trading purposes. Presently, none of our derivative positions are designated as hedges for accounting purposes.

Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. As of December 31, 2020, we had $985.0 million outstanding under the Credit Facility with a weighted average interest rate of 2.73%. An increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $9.9 million based on the balance outstanding at December 31, 2020. See “Note 7 - Borrowings” of the Notes to our Consolidated Financial Statements for more information on our Credit Facility.

Counterparty and customer credit risk

Our principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

We market our oil, natural gas and NGL production to energy marketing companies and are subject to credit risk due to the concentration of our oil, natural gas and NGL receivables with several significant customers. For the year ended December 31, 2020, two purchasers accounted for more than 10% of our revenue: Shell Trading Company (31%) and Valero Energy (23%). The inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security. We are generally paid by our purchasers within 30 to 90 days after the month of production and currently do not believe that we have a risk of not collecting. At December 31, 2020, our total receivables from the sale of our oil, natural gas and NGL production were approximately $100.3 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. We generally have the right to withhold future revenue distributions to recover past due receivables from joint interest owners. The allowance for credit losses related to our joint interest receivables is immaterial. At December 31, 2020, our joint interest receivables were approximately $11.5 million.

Our oil, natural gas and NGL commodity derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. All of the counterparties of our commodity derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional commodity derivative instruments with these or other lenders under our Credit Facility, representing institutions with investment grade ratings. We have existing International Swap Dealers Association Master Agreements ("ISDA Agreements") with our commodity derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of offset upon the occurrence of defined acts of default by either us or a counterparty to a commodity derivative, whereby the party not in default may offset all commodity derivative liabilities owed to the defaulting party against all commodity derivative asset receivables from the defaulting party. At December 31, 2020, we had a net commodity derivative liability position of $96.1 million.

ITEM 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Callon Petroleum Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three 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 three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 25, 2021 expressed an unqualified opinion.

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. 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.

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

As described further in Note 2 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and assess its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future net revenue, 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 proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment assessment. We identified the estimation of proved reserves of oil and gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense and potential impairment. 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 tested the design and operating effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and gas properties for potential impairment.

- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.
- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
    - Tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs;
    - Evaluated the method used to determine the future capital costs and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells;
    - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
    - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report 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 reserve report forecasted production by comparing to historical actual results, and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas

February 25, 2021

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Callon Petroleum Company

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Callon Petroleum Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2020, and our report dated February 25, 2021 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Houston, Texas
February 25, 2021

Callon Petroleum Company
Consolidated Balance Sheets
(In thousands, except par and share data)

	December 31, 2020	December 31, 2019
ASSETS		
Current assets:		
Cash and cash equivalents	$20,236	$13,341
Accounts receivable, net	133,109	209,463
Fair value of derivatives	921	26,056
Other current assets	24,103	19,814
Total current assets	178,369	268,674
Oil and natural gas properties, full cost accounting method:		
Evaluated properties, net	2,355,710	4,682,994
Unevaluated properties	1,733,250	1,986,124
Total oil and natural gas properties, net	4,088,960	6,669,118
Operating lease right-of-use assets	22,526	63,908
Other property and equipment, net	31,640	35,253
Deferred tax asset	—	115,720
Deferred financing costs	23,643	22,233
Other assets, net	17,730	19,932
Total assets	$4,362,868	$7,194,838
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$345,365	$490,442
Operating lease liabilities	13,175	42,858
Fair value of derivatives	97,060	71,197
Other current liabilities	41,508	47,750
Total current liabilities	497,108	652,247
Long-term debt	2,969,264	3,186,109
Operating lease liabilities	27,576	37,088
Asset retirement obligations	57,209	48,860
Fair value of derivatives	88,046	32,695
Other long-term liabilities	12,663	14,531
Total liabilities	3,651,866	3,971,530
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value, 52,500,000 shares authorized; 39,758,817 and 39,659,001 shares outstanding, respectively (1)	398	3,966
Capital in excess of par	3,222,959	3,198,076
Retained earnings (Accumulated deficit)	(2,512,355)	21,266
Total stockholders' equity	711,002	3,223,308
Total liabilities and stockholders' equity	$4,362,868	$7,194,838

(1) All share amounts (except par value) have been retroactively adjusted for the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 – Stockholders' Equity" for additional information.

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

Callon Petroleum Company
Consolidated Statements of Operations
(In thousands, except per share data)

	For the Year Ended December 31,		
	2020	**2019**	**2018**
Operating Revenues:			
Oil	$850,667	$633,107	$530,898
Natural gas	51,866	36,390	56,726
Natural gas liquids	81,295	2,075	—
Sales of purchased oil and gas	49,319	—	—
Total operating revenues	1,033,147	671,572	587,624
Operating Expenses:			
Lease operating	194,101	91,827	69,180
Production and ad valorem taxes	62,638	42,651	35,755
Gathering, transportation and processing	77,309	—	—
Cost of purchased oil and gas	51,766	—	—
Depreciation, depletion and amortization	480,631	240,642	182,783
General and administrative	37,187	45,331	35,293
Impairment of evaluated oil and gas properties	2,547,241	—	—
Merger and integration expenses	28,482	74,363	—
Other operating	10,644	4,100	5,083
Total operating expenses	3,489,999	498,914	328,094
Income (Loss) From Operations	(2,456,852)	172,658	259,530
Other (Income) Expenses:			
Interest expense, net of capitalized amounts	94,329	2,907	2,500
(Gain) loss on derivative contracts	27,773	62,109	(48,544)
(Gain) loss on extinguishment of debt	(170,370)	4,881	—
Other (income) expense	2,983	(468)	(2,896)
Total other (income) expense	(45,285)	69,429	(48,940)
Income (Loss) Before Income Taxes	(2,411,567)	103,229	308,470
Income tax expense	(122,054)	(35,301)	(8,110)
Net Income (Loss)	($2,533,621)	$67,928	$300,360
Preferred stock dividends	—	(3,997)	(7,295)
Loss on redemption of preferred stock	—	(8,304)	—
Income (Loss) Available to Common Stockholders	($2,533,621)	$55,627	$293,065
Income (Loss) Available to Common Stockholders Per Common Share [(1)]:			
Basic	($63.79)	$2.39	$13.50
Diluted	($63.79)	$2.38	$13.46
Weighted Average Common Shares Outstanding [(1)]:			
Basic	39,718	23,313	21,703
Diluted	39,718	23,340	21,773

(1) All share and per share amounts have been retroactively adjusted for the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 – Stockholders' Equity" for additional information.

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

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(In thousands, except share amounts)

	Preferred Stock		Common Stock		Capital in Excess	Retained Earnings (Accumulated	Total Stockholders'
	Shares	$	Shares (1)	$	of Par	Deficit)	Equity
Balance at 12/31/2017	1,459	$15	20,183	$2,018	$2,181,359	($327,426)	$1,855,966
Net income	—	—	—	—	—	300,360	300,360
Shares issued pursuant to employee benefit plans	—	—	4	—	533	—	533
Restricted stock	—	—	40	5	7,651	—	7,656
Common stock issued	—	—	2,530	253	287,735	—	287,988
Preferred stock dividend	—	—	—	—	—	(7,295)	(7,295)
Balance at 12/31/2018	1,459	$15	22,757	$2,276	$2,477,278	($34,361)	$2,445,208
Net income	—	—	—	—	—	67,928	67,928
Shares issued pursuant to employee benefit plans	—	—	2	—	154	—	154
Restricted stock	—	—	79	8	11,622	—	11,630
Common stock issued for Carrizo Acquisition	—	—	16,821	1,682	763,691	—	765,373
Common stock warrants reissued in conjunction with Carrizo Acquisition	—	—	—	—	10,029	—	10,029
Preferred stock dividend	—	—	—	—	—	(3,997)	(3,997)
Preferred stock redemption	(1,459)	(15)	—	—	(64,698)	—	(64,713)
Loss on redemption of preferred stock	—	—	—	—	—	(8,304)	(8,304)
Balance at 12/31/2019	—	$—	39,659	$3,966	$3,198,076	$21,266	$3,223,308
Net loss	—	—	—	—	—	(2,533,621)	(2,533,621)
Restricted stock	—	—	100	10	12,213	—	12,223
Reverse stock split	—	—	—	(3,578)	3,578	—	—
Issuance of common stock warrants	—	—	—	—	9,109	—	9,109
Other	—	—	—	—	(17)	—	(17)
Balance at 12/31/2020	—	$—	39,759	$398	$3,222,959	($2,512,355)	$711,002

(1) All share amounts have been retroactively adjusted for the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 – Stockholders' Equity" for additional information.

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

Callon Petroleum Company
Consolidated Statements of Cash Flows
(In thousands)

	Years Ended December 31,		
	2020	2019	2018
Cash flows from operating activities:			
Net income (loss)	($2,533,621)	$67,928	$300,360
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	480,631	245,936	185,605
Impairment of evaluated oil and gas properties	2,547,241	—	—
Amortization of non-cash debt related items	3,901	2,907	2,483
Deferred income tax expense	118,607	35,301	8,110
(Gain) loss on derivative contracts	27,773	62,109	(48,544)
Cash received (paid) for commodity derivative settlements, net	98,870	(3,789)	(27,272)
(Gain) loss on early extinguishment of debt	(170,370)	4,881	—
Non-cash expense related to equity share-based awards	6,773	9,767	6,289
Change in the fair value of liability share-based awards	(4,110)	1,624	375
Payments for cash-settled restricted stock unit awards	(770)	(1,425)	(4,990)
Other, net	7,857	(90)	(144)
Changes in current assets and liabilities:			
Accounts receivable	75,770	(35,071)	(17,351)
Other current assets	(6,550)	(4,166)	(7,601)
Accounts payable and accrued liabilities	(92,227)	82,290	72,842
Other	—	8,114	(2,508)
Net cash provided by operating activities	559,775	476,316	467,654
Cash flows from investing activities:			
Capital expenditures	(677,154)	(640,540)	(611,173)
Acquisitions	—	(42,266)	(718,793)
Proceeds from sales of assets	178,970	294,417	9,009
Cash paid for settlements of contingent consideration arrangements, net	(40,000)	—	—
Other, net	8,301	—	(3,100)
Net cash used in investing activities	(529,883)	(388,389)	(1,324,057)
Cash flows from financing activities:			
Borrowings on Credit Facility	5,353,000	2,455,900	500,000
Payments on Credit Facility	(5,653,000)	(895,500)	(325,000)
Payment to terminate Prior Credit Facility	—	(475,400)	—
Repayment of Carrizo's senior secured revolving credit facility	—	(853,549)	—
Repayment of Carrizo's preferred stock	—	(220,399)	—
Issuance of 9.00% Second Lien Senior Secured Notes due 2025	300,000	—	—
Discount on the issuance of 9.00% Second Lien Senior Secured Notes due 2025	(35,270)	—	—
Issuance of September 2020 Warrants	23,909	—	—
Issuance of 6.375% Senior Notes due 2026	—	—	400,000
Issuance of common stock	—	—	287,988
Payment of preferred stock dividends	—	(3,997)	(7,295)
Payment of deferred financing and debt exchange costs	(10,811)	(22,480)	(9,430)
Tax withholdings related to restricted stock units	(509)	(2,195)	(1,804)
Redemption of preferred stock	—	(73,017)	—
Other, net	(316)	—	—
Net cash provided by (used in) financing activities	(22,997)	(90,637)	844,459
Net change in cash and cash equivalents	6,895	(2,710)	(11,944)
Balance, beginning of period	13,341	16,051	27,995
Balance, end of period	$20,236	$13,341	$16,051

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

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Description of Business

Callon Petroleum Company is an independent oil and natural gas company established in 1950. The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Callon's focus is on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. The Company's activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas, as well as the Eagle Ford, which the Company entered into through its acquisition of Carrizo Oil & Gas, Inc. ("Carrizo") in late 2019. The Company's primary operations in the Permian reflect a high-return, oil-weighted drilling inventory with multiple prospective horizontal development intervals and are complemented by a well-established and repeatable cash flow generating business in the Eagle Ford.

Note 2 – Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and are presented in accordance with U.S. GAAP. The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. In the opinion of management, the accompanying audited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account balance and transaction eliminations, necessary to present fairly the Company's financial position, results of its operations and cash flows for the periods indicated. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make judgments affecting estimates and assumptions for reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Estimates of proved oil and gas reserves are used in calculating depreciation, depletion and amortization ("DD&A") of evaluated oil and gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated timing of cash outflows underlying asset retirement obligations. There are numerous uncertainties inherent in the estimation of proved oil and gas reserves and in the projection of future rates of production and the timing of development expenditures. Other significant estimates are involved in determining asset retirement obligations, acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of commodity derivative assets and liabilities, fair values of contingent consideration arrangements, fair value of second lien notes upon issuance, grant date fair value of stock-based awards, and contingency, litigation, and environmental liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

Accounts Receivable, Net

Accounts receivable, net consists primarily of receivables from oil, natural gas, and NGL purchasers and joint interest owners in properties the Company operates. The Company generally has the right to withhold future revenue distributions to recover past due receivables from joint interest owners. Generally, the Company's oil, natural gas, and NGL receivables are collected within 30 to 90 days. The Company's allowance for credit losses and bad debt expense was immaterial for all periods presented.

Concentration of Credit Risk and Major Customers

The concentration of accounts receivable from entities in the oil and gas industry may impact the Company's overall credit risk such that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not believe the loss of any one of its purchasers would materially affect its ability to sell the oil and gas it produces as other purchasers are available in its primary areas of activity. The Company had the following major customers that represented 10% or more of its total revenues for at least one of the periods presented:

	Years Ended December 31,		
	2020	**2019**	**2018**
Shell Trading Company	31%	10%	*
Valero Energy	23%	*	*
Rio Energy International, Inc.	*	26%	28%
Enterprise Crude Oil, LLC	*	19%	14%
Plains Marketing, L.P.	*	15%	21%

* - Less than 10% for the applicable year.

The Company's counterparties to its commodity derivative instruments include lenders under the Company's credit agreement ("Lender Counterparty") as well as counterparties who are not lenders under the Company's credit agreement ("Non-Lender Counterparty"). As each Lender Counterparty has an investment grade credit rating and the Company has obtained a guaranty from each Non-Lender Counterparty's parent company, which has an investment grade credit rating, the Company believes it does not have significant credit risk with its commodity derivative instrument counterparties. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of each Lender Counterparty and each Non-Lender Counterparty's parent company. The Company executes its derivative instruments with multiple counterparties to minimize its credit exposure to any individual counterparty.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration, and development activities are capitalized as oil and gas properties. Internal costs that are directly related to acquisition, exploration, and development activities, including salaries, benefits, and stock-based compensation, are capitalized to either evaluated or unevaluated oil and gas properties based on the type of activity. Internal costs related to production and similar activities are expensed as incurred.

Proceeds from the sale or disposition of evaluated and unevaluated oil and natural gas properties are accounted for as a reduction of evaluated oil and gas property costs unless the sale significantly alters the relationship between capitalized costs and estimated proved reserves, in which case a gain or loss is recognized. For the years ended December 31, 2020, 2019 and 2018, the Company did not have any sales of oil and gas properties that significantly altered such relationship.

From time to time, the Company exchanges undeveloped acreage with third parties. The exchanges are recorded at fair value and the difference is accounted for as an adjustment of capitalized costs with no gain or loss recognized pursuant to the rules governing full cost accounting, unless such adjustment would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

Capitalized oil and gas property costs are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production depletion rate is computed on a quarterly basis by dividing current quarter production by estimated proved oil and gas reserves at the beginning of the quarter then applying such depletion rate to evaluated oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus estimated future expenditures to be incurred in developing proved reserves, net of estimated salvage values.

Excluded from this amortization are costs associated with unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or the Company determines that these costs have been impaired. The Company assesses properties on an individual basis or as a group and considers the following factors, among others, to determine if these costs have been impaired: exploration program and intent to drill, remaining lease term, and the assignment of proved reserves. As a result of the downturn in the oil and gas industry as well as in the broader macroeconomic environment in 2020, the Company analyzed its unevaluated leasehold giving consideration to its updated exploration program as well as to the remaining lease term of certain unevaluated leaseholds. As a result, the Company impaired $229.6 million unevaluated leasehold costs and transferred these costs to evaluated properties during the year ended December 31, 2020.

Geological and geophysical costs not associated with specific prospects are recorded to evaluated oil and gas property costs as incurred. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unevaluated properties and the weighted average interest rate of outstanding borrowings. Capitalized interest cannot exceed gross interest expense.

Under full cost accounting rules, the Company reviews the net book value of its oil and gas properties each quarter. Under these rules, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from estimated proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the estimated proved oil and gas reserves computed using a discount factor of 10%, (b) the costs of unevaluated properties not being amortized, and (c) the lower of cost or estimated fair value of unevaluated properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of evaluated oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of oil, NGLs, and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter ("12-Month Average Realized Price"), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of commodity derivative instruments as the Company elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. Primarily as a result of the 31% decrease in the 12-Month Average Realized Price of oil, the Company recognized impairments of evaluated oil and gas properties of $2.5 billion for the year December 31, 2020. The Company did not recognize impairments of evaluated oil and gas properties for the years ended December 31, 2019 and 2018.

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from two to twenty years.

Deferred Financing Costs

Deferred financing costs associated with the Company's senior notes and second lien notes are classified as a reduction of the related senior notes or second lien notes carrying value on the consolidated balance sheets and are amortized to interest expense using the effective interest method over the terms of the related debt. Deferred financing costs associated with the revolving credit facility are classified in "Other long-term assets" in the consolidated balance sheets and are amortized to interest expense using the straight-line method over the term of the facility.

Asset Retirement Obligations

The Company records an estimate of the fair value of liabilities for obligations associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Estimates involved in determining asset retirement obligations include the future plugging and abandonment costs of wells and related facilities, the ultimate productive life of the properties, a credit-adjusted risk-free discount rate and an inflation factor in order to determine the present value of the asset retirement obligation. The present value of the asset retirement obligations is accreted each period and the increase to the obligation is reported in "Depreciation, depletion and amortization" in the consolidated statements of operations. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to evaluated oil and gas properties in the consolidated balance sheets. See "Note 14 - Asset Retirement Obligations" for additional information.

Derivative Instruments

The Company uses commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of its forecasted sales of production and achieve a more predictable level of cash flow. All commodity derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. The Company nets its commodity derivative instrument fair value amounts executed with the same counterparty to a single asset or liability pursuant to International Swap Dealers Association Master Agreements ("ISDAs"), which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company does not enter into commodity derivative instruments for speculative or trading purposes.

The Company is also party to contingent consideration arrangements that include obligations to pay or rights to receive additional consideration if commodity prices exceed specified thresholds during certain periods in the future. These contingent consideration assets and liabilities are required to be bifurcated and accounted for separately as derivative instruments as they are not considered to be clearly and closely related to the host contract, and recognized at their acquisition or divestiture date fair value in the consolidated balance sheets.

The Company has elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. As such, all gains and losses as a result of changes in the fair value of commodity derivative instruments, as well as its contingent consideration arrangements, are recognized as "(Gain) loss on derivative contracts" in the consolidated statements of operations in the period in which the changes occur. See "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" for further discussion.

Revenue Recognition

The Company recognizes revenues from the sales of oil, natural gas, and NGLs to its customers and presents them disaggregated on the Company's consolidated statements of operations. Revenue is recognized at the point in time when control of the product transfers to the customer. Revenue accruals are recorded monthly and are based on estimated production delivered to a purchaser and the expected price to be received. Variances between estimates and the actual amounts received are recorded in the month payment is received. See "Note 3 - Revenue Recognition" for further discussion.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax basis of assets and liabilities and their reported amounts in the Company's consolidated financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. U.S. GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards and tax credit carryforwards. The Company assesses the realizability of its deferred tax assets on a quarterly basis by considering all available evidence (both positive and negative) to determine whether it is more likely than not that all or a portion of the deferred tax assets will not be realized and a valuation allowance is required. See "Note 12 - Income Taxes" for further discussion of the deferred tax asset valuation allowance.

Share-Based Compensation

The Company grants restricted stock unit awards that may be settled in common stock ("RSU Equity Awards") or cash ("Cash-Settled RSU Awards"), some of which are subject to achievement of certain performance conditions. Share-based compensation expense is recognized as "General and administrative expense" in the consolidated statements of operations. The Company accounts for forfeitures of equity-based incentive awards as they occur. See "Note 10 - Share-Based Compensation" for further details of the awards discussed below.

RSU Equity Awards and Cash-Settled RSU Awards. Share-based compensation expense for RSU Equity Awards is based on the grant-date fair value and recognized over the vesting period (generally three years for employees and one year for non-employee directors) using the straight-line method. For RSU Equity Awards with vesting terms subject to a performance condition, share-based compensation expense is based on the fair value measured at each reporting period as calculated using a Monte Carlo pricing model with the estimated value recognized over the vesting period (generally three years). Cash-Settled RSU Awards subject to a performance condition that the Company expects or is required to settle in cash, are accounted for as liabilities with share-based compensation expense based on the fair value measured at each reporting period as calculated using a Monte Carlo pricing model, with the estimated fair value recognized over the vesting period (generally three years).

Cash SARs. Stock appreciation rights to be settled in cash ("Cash SARs") previously granted by Carrizo that were outstanding at closing of the Merger were canceled and converted into a Cash SAR covering shares of the Company's common stock, with the conversion calculated as prescribed in the agreement governing the Merger. The Cash SARs were recorded at their acquisition date fair value, which was determined using a Black-Scholes-Merton option pricing model, with the fair value liability subsequently remeasured at the end of each reporting period. The liability for Cash SARs is classified as "Other current liabilities" in the consolidated balance sheets as all outstanding awards are vested. The Cash SARs will expire between one and six years, depending on the date of grant.

Supplemental Cash Flow Information

The following table sets forth supplemental cash flow information for the periods indicated:

	Years Ended December 31,		
	2020	2019	2018
		(In thousands)	
Interest paid, net of capitalized amounts	$91,269	$—	$—
Income taxes paid [(1)]	—	—	—
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$44,314	$3,414	$—
Investing cash flows from operating leases	24,234	32,529	—
Non-cash investing and financing activities:			
Change in accrued capital expenditures	($64,465)	($31,475)	($52,757)
Change in asset retirement costs	8,605	13,559	8,730
Contingent consideration arrangement	—	8,512	—
ROU assets obtained in exchange for lease liabilities:			
Operating leases	$8,070	$66,914	$—
Financing leases	—	2,197	—

(1) The Company did not pay any federal income tax for any of the years in the three year period ending December 31, 2020.

Earnings per Share

The Company's basic net income (loss) attributable to common shareholders per common share is based on the weighted average number of shares of common stock outstanding for the period. Diluted net income (loss) attributable to common shareholders per common share is calculated using the treasury stock method and is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the year which include RSU Equity Awards and common stock warrants. When a loss attributable to common shareholders per common share exists, all potentially dilutive common shares outstanding are anti-dilutive and therefore excluded from the calculation of diluted weighted average shares outstanding. See "Note 6 - Earnings Per Share" for further discussion.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development, and production of crude oil, natural gas, and NGLs. All of the Company's operations are located in the United States and currently all revenues are attributable to customers located in the United States.

Recently Adopted Accounting Standards

Credit Losses. In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, followed by other related ASUs that provided targeted improvements (collectively "ASU 2016-13"). ASU 2016-13 provides financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The guidance is to be applied using a modified retrospective method and is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. The Company adopted ASU 2016-13 on January 1, 2020. The adoption of ASU 2016-13 did not have a material impact to the Company's consolidated financial statements or disclosures.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842): Amendments to the FASB Accounting Standards Codification. In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. In July 2018, the FASB issued ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. In March 2019, the FASB issued ASU No. 2019-01, Leases (Topic 842): Codification Improvements. Together these related amendments to GAAP represent ASC Topic 842, Leases ("ASC 842").

Effective January 1, 2019, the Company adopted ASU 842, using the modified retrospective approach and did not have a cumulative-effect adjustment in retained earnings as a result of the adoption. ASC 842 requires lessees to recognize a liability representing the obligation to make lease payments and a related right-of-use ("ROU") asset for virtually all lease transactions and disclose key quantitative and qualitative information about leasing arrangements. However, ASC 842 does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained. The Company engaged a third-party consultant to assist with assessing its existing contracts, as well as future potential contracts, and to determine the impact of its application on its consolidated financial statements and related disclosures. The contract evaluation process included review of drilling rig contracts, office facility leases, compressors, field vehicles and equipment, general corporate leased equipment, and other existing arrangements to support its operations that may contain a lease component.

Upon adoption, the Company implemented policy elections and practical expedients which include the following:

- package of practical expedients which allows the Company to forego reassessing contracts that commenced prior to adoption that were properly evaluated under legacy lease accounting guidance
- excluding ROU assets and lease liabilities for leases with terms that are less than one year;
- combining lease and non-lease components and accounting for them as a single lease (elected by asset class);
- excluding land easements that existed or expired prior to adoption; and
- policy election that eliminates the need for adjusting prior period comparable financial statements prepared under legacy lease accounting guidance.

Through the implementation process, the Company evaluated each of its lease arrangements and enhanced its systems to track and calculate additional information required upon adoption of this standard. Adoption of ASC 842 did not materially change the Company's consolidated statements of operations or consolidated statements of cash flows. See "Note 13 - Leases" for further discussion.

Recently Issued Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("ASU 2020-04") followed by ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope ("ASU 2021-01"), issued in January 2021 to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide 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. Generally, the guidance is to be applied as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. ASU 2020-04 and ASU 2021-01 are effective for all entities through December 31, 2022. As of December 31, 2020, the Company has not elected to use the optional guidance and continues to evaluate the options provided by ASU 2020-04 and ASU 2021-01. Please refer to "Note 7 – Borrowings" for discussion of the use of the adjusted LIBO rate in connection with borrowings under the Credit Facility.

Note 3 – Revenue Recognition

Revenue from contracts with customers

Oil sales

Under the Company's oil sales contracts it sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the point of delivery at the net price received.

Natural gas and NGL sales

Effective January 1, 2020, certain of our natural gas processing agreements were modified to allow the Company to take title to NGLs resulting from the processing of our natural gas. As a result, sales and reserve volumes, prices, and revenues for NGLs and natural gas are presented separately for periods subsequent to January 1, 2020. For periods prior to January 1, 2020, except for sales and reserve volumes, prices, and revenues specifically associated with Carrizo, sales and reserve volumes, prices, and revenues for NGLs were presented with natural gas.

Under the Company's natural gas sales processing contracts, it delivers natural gas to a midstream processing entity which gathers and processes the natural gas and remits proceeds to the Company for the resulting sale of NGLs and residue gas. The Company evaluates whether the processing entity is the principal or the agent in the transaction for each of our natural gas processing agreements and have concluded that we maintain control through processing or we have the right to take residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. We recognize revenue when control transfers to the purchaser at the delivery point based on the contractual index price received.

Contractual fees associated with gathering, processing, treating and compression, as well as any transportation fees incurred to deliver the product to the purchaser, for the majority of the Company's natural gas processing agreements were previously recorded as a reduction of revenue. As a result of the modifications to certain of the Company's natural gas processing agreements, as well as the natural gas processing agreements assumed in the Carrizo Acquisition, the Company now recognizes revenue for natural gas and NGLs on a gross basis with gathering, transportation and processing fees recognized separately as "Gathering, transportation and processing" in its consolidated statements of operations as the Company maintains control throughout processing. These changes impact the comparability of 2020 with prior periods. For the years ended December 31, 2019 and 2018, $10.5 million and $7.6 million of gathering, transportation, and processing fees were recognized as a reduction to natural gas revenues in the consolidated statement of operations.

Oil and gas purchase and sale arrangements

Sales of purchased oil and gas represent revenues the Company receives from sales of commodities purchased from a third-party. The Company recognizes these revenues and the purchase of the third-party commodities, as well as any costs associated with the purchase, on a gross basis, as the Company acts as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer.

Accounts receivable from revenues from contracts with customers

Net accounts receivable include amounts billed and currently due from revenues from contracts with customers of our oil and natural gas production, which had a balance at December 31, 2020 and 2019 of $100.3 million and $165.3 million, respectively, and are presented in "Accounts receivable, net" in the consolidated balance sheets. The decrease from December 31, 2019 is primarily due to the lower realized price of oil.

Transaction price allocated to remaining performance obligations

For the Company's product sales that have a contract term greater than one year, it has utilized the practical expedient in Accounting Standards Codification 606-10-50-14, which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation, therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for sales may not be received for 30 to 90 days after the date production is delivered, and as a result, 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. The Company records the differences between estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant.

Note 4 – Acquisitions and Divestitures

2020 Acquisitions and Divestitures

ORRI Transaction. On September 30, 2020, the Company sold an undivided 2.0% (on an 8/8ths basis) overriding royalty interest, proportionately reduced to the Company's net revenue interest, in and to the Company's operated leases, excluding certain interests to Chambers Minerals, LLC, a private investment vehicle managed by Kimmeridge Energy, for an aggregate purchase price of $140.0 million ("ORRI Transaction"), with an effective date of October 1, 2020. After adjusting for costs associated with the sale, the net proceeds of $135.8 million were used to repay borrowings outstanding under the Credit Facility.

Non-Operated Working Interest Transaction. On November 2, 2020, the Company sold substantially all of its non-operated assets for net proceeds of approximately $29.6 million, which were used to repay borrowings outstanding under the Credit Facility. The transaction had an effective date of September 1, 2020 and is subject to post-closing adjustments.

The aggregate net proceeds for each of the 2020 divestitures discussed above were recognized as a reduction of evaluated oil and gas properties with no gain or loss recognized as the divestitures did not significantly alter the relationship between capitalized costs and estimated proved reserves.

The Company did not have any material acquisitions for the year ended December 31, 2020.

2019 Acquisitions and Divestitures

Carrizo Oil & Gas, Inc. Merger. On December 20, 2019, the Company completed its acquisition of Carrizo in an all-stock transaction (the "Merger" or the "Carrizo Acquisition"). Under the terms of the Merger, each outstanding share of Carrizo common stock was converted into 1.75 shares of the Company's common stock. The Company issued approximately 168.2 million shares of common stock at a price of $4.55 per share, resulting in total consideration paid by the Company to the former Carrizo shareholders of approximately $765.4 million. In connection with the closing of the Merger, the Company funded the redemption of Carrizo's 8.875% Preferred Stock, repaid the outstanding principal under Carrizo's revolving credit facility and assumed all of Carrizo's senior notes. See "Note 7 - Borrowings" for further details.

The Merger 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 with information available at that time. 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 gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for 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 final allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Final Purchase Price Allocation (In thousands)
Consideration:	
Fair value of the Company's common stock issued	$765,373
Total consideration	$765,373
Liabilities:	
Accounts payable	$37,657
Revenues and royalties payable	52,449
Operating lease liabilities - current	29,924
Fair value of derivatives - current	61,015
Other current liabilities	88,346
Long-term debt	1,984,135
Operating lease liabilities - non-current	30,070
Asset retirement obligation	26,151
Fair value of derivatives - non-current	26,960
Other long-term liabilities	17,887
Common stock warrants	10,029
Total liabilities assumed	$2,364,623
Assets:	
Accounts receivable, net	$48,479
Fair value of derivatives - current	17,451
Other current assets	11,640
Evaluated oil and natural gas properties	2,133,280
Unevaluated properties	679,900
Other property and equipment	9,614
Fair value of derivatives - non-current	4,518
Deferred tax asset	162,629
Operating lease right-of-use-assets	59,907
Other long term assets	2,578
Total assets acquired	$3,129,996

During the measurement period, the Company made adjustments to certain of the assets acquired and liabilities assumed, primarily due to the final tax returns of Carrizo which provided the underlying tax basis of Carrizo's assets and liabilities. Approximately $556.2 million of revenues and $200.9 million of direct operating expenses attributed to the Carrizo Acquisition were included in the Company's consolidated statements of operations for the year ended December 31, 2020. For the period from the closing date of the Carrizo Acquisition on December 20, 2019 through December 31, 2019, approximately $28.6 million of revenues and $7.0 million of direct operating expenses were included in the Company's consolidated statements of operations for the year ended December 31, 2019.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma combined condensed financial data for the years ended December 31, 2019 and 2018 was derived from the historical financial statements of the Company giving effect to the Merger, as if it had occurred on January 1, 2018. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for Carrizo's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert Carrizo's outstanding shares of common stock and equity awards as of the closing date of the Merger, (ii) the depletion of Carrizo's fair-valued proved oil and natural gas properties and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of approximately $58.8 million for the year ended December 31, 2019 and acquisition-related costs incurred by Carrizo that totaled approximately $15.6 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 result from the Merger or any estimated costs that have been or will be incurred by the Company to integrate the Carrizo assets. 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 primarily acreage acquisitions and their results were not deemed material.

The pro forma consolidated statements of operations data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Merger taken place on January 1, 2018 and is not intended to be a projection of future results.

	Years Ended December 31,	
	2019	**2018**
	(In thousands)	
Revenues	$1,620,357	$1,661,171
Income from operations	614,668	767,628
Net income	369,777	734,527
Basic earnings per common share	$0.89	$1.87
Diluted earnings per common share	$0.89	$1.87

In conjunction with the Carrizo Acquisition, the Company incurred costs totaling $28.5 million and $74.4 million for the years ended December 31, 2020 and 2019, respectively, comprised of severance costs of $6.2 million and $28.8 million for the years ended December 31, 2020 and 2019, respectively, and other merger and integration expenses of $22.3 million and $45.6 million for the years ended December 31, 2020 and 2019, respectively. Through December 31, 2020, the Company has incurred cumulative costs associated with the Carrizo Acquisition of $102.9 million comprised of severance costs of $35.8 million and other merger and integration expenses of $67.1 million. As of December 31, 2020 and 2019, $5.7 million and $52.4 million, respectively, remained accrued and is included as a component of "Accounts payable and accrued liabilities" in the consolidated balance sheets.

Ranger Divestiture. In the second quarter of 2019, the Company completed its divestiture of certain non-core assets in the southern Midland Basin (the "Ranger Divestiture") for net cash proceeds of $244.9 million. The transaction also provided for potential additional contingent consideration in payments of up to $60.0 million based on West Texas Intermediate average annual pricing over a three-year period. See "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" for further discussion of this contingent consideration arrangement. The divestiture encompasses the Ranger operating area in the southern Midland Basin which included approximately 9,850 net Wolfcamp acres with an average 66% working interest. The net cash proceeds were recognized as a reduction of evaluated oil and gas properties with no gain or loss recognized as the divestitures did not significantly alter the relationship between capitalized costs and estimated proved reserves.

2018 Acquisitions and Divestitures

On August 31, 2018, the Company completed the acquisition of approximately 28,000 net surface acres in the Spur operating area, located in the Delaware Basin, from Cimarex Energy Company, for a net cash consideration of approximately $539.5 million (the "Delaware Asset Acquisition"). The Company funded the Delaware Asset Acquisition with net proceeds from both the common stock offering completed on May 30, 2018 and the issuance of the 6.375% Senior Notes. See “Note 7 - Borrowings” and “Note 11 - Stockholders’ Equity” for further details of these offerings.

The Delaware Asset 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 gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for 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 final allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation
	(In thousands)
Assets	
Oil and natural gas properties	
Evaluated properties	$253,089
Unevaluated properties	287,000
Total oil and natural gas properties	$540,089
Total assets acquired	$540,089
Liabilities	
Asset retirement obligations	($570)
Total liabilities assumed	($570)
Net Assets Acquired	$539,519

Approximately $27.3 million of revenues and $9.9 million of direct operating expenses attributed to the Delaware Asset Acquisition are included in the Company’s consolidated statements of operations for the period from the closing date on August 31, 2018 through December 31, 2018.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma financial information presents a summary of the Company’s consolidated results of operations for the year ended December 31, 2018, assuming the Delaware Asset Acquisition had been completed as of January 1, 2017, including adjustments to reflect the acquisition date fair values assigned to the assets acquired and liabilities assumed. The pro forma financial information does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The Company believes the assumptions used provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the Delaware Asset Acquisition.

	Year Ended December 31, 2018
	(In thousands)
Revenues	$669,236
Income from operations	299,090
Net income	324,318
Basic earnings per common share	$1.49
Diluted earnings per common share	$1.49

Other. In addition, the Company completed various acquisitions of additional working interests and mineral rights, and associated production volumes, in the Company’s existing core operating areas within the Permian. In the first quarter of 2018, the Company completed acquisitions within Monarch and WildHorse operating areas for aggregate net cash consideration of approximately $37.8 million. In the fourth quarter of 2018, the Company completed acquisitions of leasehold interests and mineral rights within its WildHorse and Spur operating areas for net cash consideration of approximately $87.9 million.

The Company did not have any material divestitures for the year ended December 31, 2018.

Note 5 – Property and Equipment, Net

As of December 31, 2020 and 2019, total property and equipment, net consisted of the following:

	As of December 31,	
	2020	2019
Oil and natural gas properties, full cost accounting method	(In thousands)	
Evaluated properties	$7,894,513	$7,203,482
Accumulated depreciation, depletion, amortization and impairments	(5,538,803)	(2,520,488)
Evaluated properties, net	2,355,710	4,682,994
Unevaluated properties		
Unevaluated leasehold and seismic costs	1,532,304	1,843,725
Capitalized interest	200,946	142,399
Total unevaluated properties	1,733,250	1,986,124
Total oil and natural gas properties, net	$4,088,960	$6,669,118
Other property and equipment	$60,287	$67,202
Accumulated depreciation	(28,647)	(31,949)
Other property and equipment, net	$31,640	$35,253

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $36.2 million for the years ended December 31, 2020, 2019, and $28.0 million for the year ended December 31, 2018, respectively. The Company capitalized interest costs to unproved properties totaling $88.6 million, $78.5 million and $56.2 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Impairment of Evaluated Oil and Gas Properties

Primarily as a result of the significant reduction in the 12-Month Average Realized Price of crude oil, the Company recognized impairments of evaluated oil and gas properties of $2.5 billion for the year December 31, 2020. The Company did not recognize impairments of evaluated oil and gas properties for the years ended December 31, 2019 and 2018.

Details of the 12-Month Average Realized Price of crude oil for the years ended December 31, 2020, 2019, and 2018 are summarized in the table below:

	Years Ended December 31,		
	2020	2019	2018
Impairment of evaluated oil and natural gas properties (In thousands)	$2,547,241	$—	$—
Beginning of period 12-Month Average Realized Price ($/Bbl)	$53.90	$58.40	$49.48
End of period 12-Month Average Realized Price ($/Bbl)	$37.44	$53.90	$58.40
Percent increase (decrease) in 12-Month Average Realized Price	(31%)	(8%)	18%

The Company currently estimates the range of the first quarter of 2021 cost center ceiling, at the high end, would exceed the net book value of oil and gas properties, resulting in no impairment in the carrying value of evaluated oil and gas properties, and at the low end, would result in an impairment in the carrying value of evaluated oil and gas properties of $100.0 million. This is based on an estimated 12-Month Average Realized price of crude oil of approximately $40.23 per Bbl as of March 31, 2021, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. Declines in the 12-Month Average Realized Price of crude oil in subsequent quarters could result in a lower present value of the estimated future net revenues from proved oil and gas reserves and may result in additional impairments of evaluated oil and gas properties.

As a result of the downturn in the oil and gas industry as well as in the broader macroeconomic environment in 2020, the Company analyzed its unevaluated leasehold giving consideration to its updated exploration program as well as to the remaining lease term of certain unevaluated leaseholds. As a result of this analysis, the Company impaired $229.6 million unevaluated leasehold costs and transferred to evaluated properties during the year ended December 31, 2020.

Unevaluated property costs not subject to amortization as of December 31, 2020 were incurred in the following periods:

	2020	2019	2018	2017 and Prior	Total
			(In thousands)		
Unevaluated property costs	$113,078	$680,456	$439,478	$500,238	$1,733,250

Note 6 – Earnings Per Share

Basic earnings (loss) per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the potential dilutive impact of non-vested restricted shares and unexercised warrants outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. For the year ended December 31, 2020, the Company reported a loss available to common stockholders. As a result, the calculation of diluted weighted average common shares outstanding excluded all potentially dilutive common shares outstanding.

The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended December 31,		
	2020	**2019**	**2018**
	(In thousands, except per share amounts)		
Net income (loss)	($2,533,621)	$67,928	$300,360
Preferred stock dividends (1)	—	(3,997)	(7,295)
Loss on redemption of preferred stock	—	(8,304)	—
Income (loss) available to common stockholders	($2,533,621)	$55,627	$293,065
Basic weighted average common shares outstanding (2)	39,718	23,313	21,703
Dilutive impact of restricted stock (2)	—	27	70
Diluted weighted average common shares outstanding (2)	39,718	23,340	21,773
Income (Loss) Available to Common Stockholders Per Common Share (2)			
Basic	($63.79)	$2.39	$13.50
Diluted	($63.79)	$2.38	$13.46
Restricted stock (2)(3)	581	90	16
Warrants (2)(3)	2,564	9	0

(1) The Company redeemed all outstanding shares of its 10% Series A Cumulative Preferred Stock ("Preferred Stock") on July 18, 2019 and all dividends ceased to accrue upon redemption.

(2) Shares and per share data have been retroactively adjusted to reflect the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 – Stockholders' Equity" for additional information.

(3) Shares excluded from the diluted earnings per share calculation because their effect would be anti-dilutive.

Note 7 – Borrowings

The Company’s borrowings consisted of the following:

	As of December 31,	
	2020	2019
	(In thousands)	
Senior Secured Revolving Credit Facility due 2024	$985,000	$1,285,000
9.00% Second Lien Senior Secured Notes due 2025	516,659	—
6.25% Senior Notes due 2023	542,720	650,000
6.125% Senior Notes due 2024	460,241	600,000
8.25% Senior Notes due 2025	187,238	250,000
6.375% Senior Notes due 2026	320,783	400,000
Total principal outstanding	3,012,641	3,185,000
Unamortized discount on Second Lien Notes	(41,820)	—
Unamortized premium for 6.25% Senior Notes	2,917	4,838
Unamortized premium for 6.125% Senior Notes	3,236	5,344
Unamortized premium for 8.25% Senior Notes	3,240	5,286
Unamortized deferred financing costs for Second Lien Notes	(3,931)	—
Unamortized deferred financing costs for Senior Notes	(7,019)	(14,359)
Total carrying value of borrowings (1)	$2,969,264	$3,186,109

(1) Excludes unamortized deferred financing costs related to the Company’s Credit Facility of $23.6 million and $22.2 million as of December 31, 2020 and 2019, respectively, which are classified in “Deferred financing costs” in the consolidated balance sheets.

Senior Secured Revolving Credit Facility

On December 20, 2019, upon consummation of the Merger, the Company entered into the senior secured revolving credit facility with a syndicate of lenders (the “Credit Facility”). The credit agreement governing the Credit Facility provides for interest-only payments until December 20, 2024 (subject to springing maturity dates of (i) January 14, 2023 if the 6.25% Senior Notes due 2023 (the “6.25% Senior Notes”) are outstanding at such time, (ii) July 2, 2024 if the 6.125% Senior Notes due 2024 (the “6.125% Senior Notes”) are outstanding at such time, and (iii) if the Second Lien Notes, defined below, are outstanding at such time, the date which is 182 days prior to the maturity of any of the 6.25% Senior Notes or the 6.125% Senior Notes, in each case, to the extent a principal amount of more than $100.0 million with respect to each such issuance is outstanding as of such date), when the Credit Facility matures and any outstanding borrowings are due. The maximum credit amount under the Credit Facility is $5.0 billion.

On December 31, 2020, the borrowing base and the elected commitment amount under the revolving credit facility was $1.6 billion, with borrowings outstanding of $985.0 million at a weighted average interest rate of 2.73%, and letters of credit outstanding of $25.2 million. The borrowing base under the credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering the Company’s major producing properties. The capitalized terms which are not defined in this description of the Credit Facility shall have the meaning given to such terms in the credit agreement.

On May 7, 2020, the Company entered into the first amendment to its credit agreement governing the Credit Facility. The amendment included, but was not limited to the following:

- Established a new borrowing base as a result of the spring 2020 scheduled redetermination in the amount of $1.7 billion and reduced the elected commitments to $1.7 billion, which were subsequently revised as described below;
- Permits the incurrence of, among other things, new second lien notes in 2020 exchanged for unsecured notes in an aggregate principal amount of up to $400.0 million without triggering a reduction in the borrowing base so long as any such second lien notes are subject to an intercreditor agreement providing that the liens securing the second lien notes rank junior to the liens securing the credit agreement;
- Provides that testing of the Leverage Ratio is suspended until March 31, 2022, as of which testing date and the last day of each fiscal quarter ending thereafter, such ratio may not exceed 4.00 to 1.00;
- Provides for testing of the Secured Leverage Ratio that may not exceed 3.00 to 1.00 on a quarterly basis beginning with the quarter ended March 31, 2020 through the quarter ending December 31, 2021; and
- Provided that the testing of the Current Ratio was suspended until September 30, 2020, as of which testing date and the last day of each fiscal quarter ending thereafter, such ratio may not be less than 1.00 to 1.00

On September 30, 2020, the Company entered into the second amendment to its credit agreement governing the Credit Facility. The amendment, among other things, reaffirmed the $1.7 billion borrowing base as a result of the fall 2020 scheduled redetermination.

Also on September 30, 2020, the Company entered into the third amendment to its credit agreement governing the Credit Facility. The amendment included, but was not limited to the following:

- Established a new borrowing base of $1.6 billion and reduced the elected commitments to $1.6 billion in connection with the issuance of the September 2020 Second Lien Notes and September 2020 Warrants, described below, and the ORRI Transaction;
- Permitted the issuance of the $300.0 million of September 2020 Second Lien Notes as contemplated by the Purchase Agreement, described below, without triggering a reduction in the borrowing base;
- Extends through the end of 2021 the time period during which second lien notes issued in exchange for unsecured notes may be issued without triggering a reduction in the borrowing base; and
- If the Second Lien Notes are outstanding at such time, caused the maturity of the Credit Facility to spring forward to a date which is 182 days prior to the maturity of any of the 6.25% Senior Notes or the 6.125% Senior Notes, in each case, to the extent a principal amount of more than $100.0 million with respect to each such issuance is outstanding as of such date.

Borrowings outstanding under the credit agreement bear interest at the Company's option at either (i) a base rate for a base rate loan plus a margin between 1.00% to 2.00%, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus a margin between 2.00% to 3.00%. The Company also incurs commitment fees at rates ranging between 0.375% to 0.500% on the unused portion of lender commitments, which are included in "Interest expense, net" in the consolidated statements of operations.

The Company terminated the Sixth Amended and Restated Credit Agreement to the Credit Facility (the "Prior Credit Facility"), which was entered into on May 25, 2017, upon entering into the Credit Facility described above. As a result of terminating the Prior Credit Facility, the Company recorded a loss on extinguishment of debt of $4.9 million, which was comprised solely of the write-off of unamortized deferred financing costs associated with the Prior Credit Facility.

Second Lien Notes

On September 30, 2020, the Company entered into a Purchase Agreement (the "Purchase Agreement") where it issued (i) $300.0 million in aggregate principal amount of its 9.00% Second Lien Senior Secured Notes due 2025 (the "September 2020 Second Lien Notes") and (ii) warrants for 7.3 million shares of the Company's common stock, with a term of five years and an exercise price of $5.60 per share, exercisable only on a net share settlement basis (the "September 2020 Warrants"), for aggregate consideration of $294.0 million. The Company used the proceeds, net of issuance costs, of approximately $288.6 million to repay borrowings outstanding under the Credit Facility. The Company also entered into a registration rights agreement with the purchaser of the September 2020 Second Lien Notes.

Net proceeds were allocated to the September 2020 Warrants based on their fair value on the date of issuance with the remaining net proceeds allocated to the September 2020 Second Lien Notes. The fair value of the September 2020 Warrants was calculated by a third-party valuation specialist using a Black-Scholes-Merton option pricing model, incorporating the following assumptions at the issuance date:

	Issuance Date Fair Value Assumptions
Exercise price	$5.60
Expected term (in years)	5.0
Expected volatility	116.3%
Risk-free interest rate	0.3%
Dividend yield	—%

See "Note 9 - Fair Value Measurements" for further discussion.

The September 2020 Second Lien Notes will mature on the earlier of (i) April 1, 2025 and (ii) 91 days prior to the maturity date of any outstanding unsecured notes in a principal amount at or greater than $100.0 million and have interest payable semi-annually each April 1 and October 1, commencing on April 1, 2021.

The Company may redeem the September 2020 Second Lien Notes in accordance with the following terms: (1) prior to October 1, 2022, a redemption of up to 35% of the principal in an amount not greater than the net proceeds from certain equity offerings, and within 180 days of the closing date of such equity offerings, at a redemption price of 109.00% of principal, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption, if at least 65% of the principal will remain outstanding after such redemption; (2) prior to October 1, 2022, a redemption of all or part of the principal at a price of 100% of the principal amount redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to, but excluding, the date of redemption; and (3) subsequent to October 1, 2022, a redemption, in whole or in part, at redemption prices decreasing annually from 105.00% to 100% of the principal amount redeemed plus accrued and unpaid interest.

Upon the occurrence of certain change of control events, each holder of the September 2020 Second Lien Notes may require the Company to repurchase all or a portion of the September 2020 Second Lien Notes at a price of 101% of the principal amount repurchased, plus accrued and unpaid interest, if any, to, but excluding, the date of repurchase.

Senior Unsecured Notes Exchange

On November 2, 2020, the Company entered into an Exchange Agreement (the "Exchange Agreement") by and among the Company and certain holders (the "Holders") of the Company's 6.25% Senior Notes, 6.125% Senior Notes, 8.25% Senior Notes, and 6.375% Senior Notes (each as defined in this footnote and together the "Senior Unsecured Notes"). Upon closing on November 13, 2020, pursuant to the Exchange Agreement, the Company agreed to exchange $389.0 million of aggregate principal amount of the Senior Unsecured Notes held by the Holders for $216.7 million aggregate principal amount of newly issued 9.00% Second Lien Senior Secured Notes due 2025 (the "November 2020 Second Lien Notes" and together with the September 2020 Second Lien Notes the "Second Lien Notes") at a weighted average exchange ratio of approximately $557 per $1,000 of principal exchanged. The November 2020 Second Lien Notes were issued under the Company's indenture dated as of September 30, 2020. Pursuant to the Exchange Agreement, the Company also agreed to issue to the Holders warrants for approximately 1.75 million shares of the Company's common stock, with a term of five years and an exercise price of $5.60 per share, exercisable only on a net share settlement basis (the "November 2020 Warrants").

The Company assessed the debt exchange to determine whether it should be accounted for pursuant to Financial Accounting Standards Board's Accounting Standard Codification ("ASC") Topic 470-60, Troubled Debt Restructurings by Debtors, or pursuant to ASC Topic 470-50, Modifications and Extinguishments ("ASC 470-50"). This assessment requires judgments to be made with respect to whether or not an entity is experiencing financial difficulty. It was determined that the Company was not experiencing financial difficulty and could obtain funds at market rates similar to other non-troubled debtors, therefore the Company accounted for the exchange as an extinguishment of debt in accordance with ASC 470-50. As the November 2020 Second Lien Notes were issued with the November 2020 Warrants, the $216.7 million aggregate principal amount was allocated between the November 2020 Second Lien Notes and the November 2020 Warrants based on their relative fair values at the exchange date. This resulted in $207.6 million allocated to the November 2020 Second Lien Notes and $9.1 million allocated to the November 2020 Warrants. The Company recognized a gain on the extinguishment of debt of $170.4 million in its consolidated statement of operations, which consisted of the carrying values of the Senior Unsecured Notes exchanged less the aggregate principal amount of the November 2020 Second Lien Notes issued, net of the associated debt discount of $9.1 million, which was based on the November 2020 Second Lien Notes' allocated fair value on the exchange date.

The fair value of the November 2020 Second Lien Notes was calculated by a third-party valuation specialist using a discounted cash flow model. Significant inputs into the calculation included the redemption premiums, described below, as well as redemption assumptions provided by the Company. The fair value of the November 2020 Warrants was calculated using a Black-Scholes-Merton option pricing model, incorporating the following assumptions at the issuance date:

	Issuance Date Fair Value Assumptions
Exercise price	$5.60
Expected term (in years)	4.9
Expected volatility	98.4%
Risk-free interest rate	0.4%
Dividend yield	—%

Senior Unsecured Notes

6.25% Senior Notes. The Company's 6.25% Senior Notes, which were assumed upon consummation of the Merger, mature on April 15, 2023 and have interest payable semi-annually each April 15 and October 15. The Company may redeem all or a portion of the 6.25% Senior Notes at redemption prices decreasing from 103.125% to 100% of the principal amount on April 15, 2021, plus accrued and unpaid interest. Following a change of control, each holder of the 6.25% Senior Notes may require the Company to repurchase the 6.25% Senior Notes for cash at a price equal to 101% of the principal amount purchased, plus any accrued and unpaid interest.

6.125% Senior Notes. The Company's 6.125% Senior Notes mature on October 1, 2024 and have interest payable semi-annually each April 1 and October 1. The Company may redeem all or a portion of the 6.125% Senior Notes at redemption prices decreasing from 104.594% to 100% of the principal amount on October 1, 2022, plus accrued and unpaid interest. Following a change of control, each holder of the 6.125% Senior Notes may require the Company to repurchase all or a portion of the 6.125% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest.

8.25% Senior Notes. The Company's 8.25% Senior Notes due 2025 (the "8.25% Senior Notes"), which were assumed upon consummation of the Merger, mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. Since July 15, 2020, the Company may redeem all or a portion of the 8.25% Senior Notes at redemption prices decreasing annually from 106.188% to 100% of the principal amount redeemed plus accrued and unpaid interest. Following a change of control, each holder of the 8.25% Senior Notes may require the Company to repurchase the 8.25% Senior Notes for cash at a price equal to 101% of the principal amount purchased, plus any accrued and unpaid interest.

6.375% Senior Notes. On June 7, 2018, the Company issued $400.0 million aggregate principal amount of 6.375% Senior Notes due 2026 (the "6.375% Senior Notes"), which mature on July 1, 2026 and have interest payable semi-annually each January 1 and July 1. The Company used the net proceeds from the offering of approximately $394.0 million, after deducting initial purchasers' discounts and estimated offering expenses, to fund a portion of the Delaware Asset Acquisition described above.

The Company may redeem the 6.375% Senior Notes in accordance with the following terms: (1) prior to July 1, 2021, a redemption of up to 35% of the principal in an amount not greater than the net proceeds from certain equity offerings, and within 180 days of the closing date of such equity offerings, at a redemption price of 106.375% of principal, plus accrued and unpaid interest, if any, to the date of the redemption, if at least 65% of the principal will remain outstanding after such redemption; (2) prior to July 1, 2021, a redemption of all or part of the principal at a price of 100% of principal of the amount redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of the redemption; and (3) subsequent to July 1, 2021, a redemption, in whole or in part, at redemption prices decreasing annually from 103.188% to 100% of the principal amount redeemed plus accrued and unpaid interest. Following a change of control, each holder of the 6.375% Senior Notes may require the Company to repurchase all or a portion of the 6.375% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest, if any, to the date of repurchase.

Each of the Senior Unsecured Notes described above are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantor are minor.

Restrictive covenants

The Company's credit agreement contains certain covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios.

Under the credit agreement, the Company must maintain the following financial covenants determined as of the last day of the quarter, each as described above: (1) a Secured Leverage Ratio of no more than 3.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. The Company was in compliance with these covenants at December 31, 2020.

The credit agreement and the indentures governing our Senior Unsecured Notes also place restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company's common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement and indentures are subject to customary events of default. If an event of default occurs and is continuing, the holders or lenders may elect to accelerate amounts due (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

Note 8 – Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil, natural gas and NGL prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil, natural gas and NGL production. The Company utilizes a mix of collars, swaps, and put and call options to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The Company typically has numerous commodity derivative instruments outstanding with a counterparty that were executed at various dates, for various contract types, commodities and time periods. This often results in both commodity derivative asset and liability positions with that counterparty. The Company nets its commodity derivative instrument fair values executed with the same counterparty to a single asset or liability pursuant to International Swap Dealers Association Master Agreements ("ISDA Agreements"), which provide for net settlement over the term of the contract and in the event of default or termination of the contract. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

As of December 31, 2020, the Company has outstanding commodity derivative instruments with sixteen counterparties to minimize its credit exposure to any individual counterparty. All of the counterparties to the Company's commodity derivative instruments are also lenders under the Company's credit agreement. Therefore, each of the Company's counterparties allow the Company to satisfy any need for margin obligations associated with commodity derivative instruments where the Company is in a net liability position with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Because each of the Company's counterparties has an investment grade credit rating, the Company believes it does not have significant credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its commodity derivative instruments. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of each counterparty.

While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument. See "Note 9 - Fair Value Measurements" for further discussion.

Financial statement presentation and settlements

Settlements of the Company's commodity derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a benchmark price, such as the NYMEX price. To determine the fair value of the Company's derivative instruments, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See "Note 9 - Fair Value Measurements" for additional information regarding fair value.

Contingent consideration arrangements

Ranger Divestiture. The Company's Ranger Divestiture provides for potential contingent consideration to be received by the Company if commodity prices exceed specified thresholds for the next year. See "Note 4 - Acquisitions and Divestitures" and "Note 9 - Fair Value Measurements" for further discussion. This contingent consideration arrangement is summarized in the table below (in thousands except for per Bbl amounts):

	Year	Threshold (1)	Contingent Receipt - Annual	Threshold (1)	Contingent Receipt - Annual	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Remaining Contingent Receipt - Aggregate Limit (3)
Remaining Potential Settlement	2021	Greater than $60/Bbl, less than $65/Bbl	$9,000	Equal to or greater than $65/Bbl	$20,833	(2)	(2)	$20,833

(1) The price used to determine whether the specified thresholds have been met is the average of the final monthly settlements for each month during each annual period end for NYMEX Light Sweet Crude Oil Futures, as reported by the CME Group Inc.

(2) Cash received for settlements of contingent consideration arrangements are classified as cash flows from financing activities up to the divestiture date fair value with any excess classified as cash flows from operating activities. Therefore, if the commodity price threshold is reached, $8.5 million of the next contingent receipt will be presented in cash flows from financing activities with the remainder presented in cash flows from operating activities.

(3) The specified pricing threshold for both 2019 and 2020 was not met. As such, approximately $20.8 million remains for potential settlements in future years.

As a result of the Carrizo Acquisition, the Company assumed all contingent consideration arrangements previously entered into by Carrizo. These contingent consideration arrangements are summarized below:

Contingent ExL Consideration

	Year	Threshold (1)	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Contingent Payment - Annual	Remaining Contingent Payments - Aggregate Limit
					(In thousands)	
Remaining Potential Settlement	2021	$50.00	(2)	(2)	($25,000)	($25,000) (3)

(1) The price used to determine whether the specified threshold for each year has been met is the average daily closing spot price per barrel of WTI crude oil as measured by the U.S. Energy Information Administration ("U.S. EIA").

(2) Cash paid for settlements of contingent consideration arrangements are classified as cash flows from investing activities up to the acquisition date fair value with any excess classified as cash flows from operating activities. In January 2020, the Company paid $50.0 million as the specified pricing threshold for 2019 was met. Therefore, if the commodity price threshold is reached in 2021, $19.2 million of the next contingent payment will be presented in cash flows from investing activities with the remainder presented in cash flows from operating activities.

(3) The specified pricing threshold for 2020 was not met. Only $25.0 million remains for potential settlements in future years.

Additionally, as part of the Carrizo Acquisition, the Company acquired other contingent consideration arrangements where the Company could receive payments if certain pricing thresholds were met in 2019 and 2020, which ranged between $53.00 - $60.00 per barrel of oil or $3.18 - $3.30 per MMBtu of natural gas. The specified pricing thresholds for each of these other contingent consideration arrangements for 2020 were not met, therefore there were no payments from the contingent consideration arrangements acquired in the Carrizo Acquisition in January 2021. In January 2020, the Company received $10.0 million as the specified pricing thresholds for 2019 were met for certain of the contingent consideration arrangements. These cash receipts are classified as cash flows from investing activities in the consolidated statements of cash flows. Each of these other contingent consideration arrangements acquired in the Carrizo Acquisition expired at the end of the 2020.

Warrants

The Company determined that the September 2020 Warrants issued with the September 2020 Second Lien Notes are required to be accounted for as a derivative instrument. The September 2020 Warrants are exercisable only on a net share settlement basis. The Company records the September 2020 Warrants as a liability on its consolidated balance sheet measured at fair value as a component of "Fair value of derivatives" with gains and losses as a result of changes in the fair value of the September 2020 Warrants recorded as "(Gain) loss on derivative contracts" in the consolidated statements of operations in the period in which the changes occur. Upon issuance, the Company recorded a liability for the September 2020 Warrants of $23.9 million and as of December 31, 2020, the liability for the September 2020 Warrants was $79.4 million. See "Note 18 - Subsequent Events" for further discussion.

Derivatives not designated as hedging instruments

The Company records its derivative instruments at fair value in the consolidated balance sheets and records changes in fair value as "(Gain) loss on derivative contracts" in the consolidated statements of operations. Settlements are also recorded as a gain or loss on derivative contracts in the consolidated statements of operations. As previously discussed, the Company's commodity derivative contracts are subject to master netting arrangements. The Company's policy is to present the fair value of derivative contracts on a net basis in the consolidated balance sheet. The following presents the impact of this presentation to the Company's recognized assets and liabilities for the periods indicated:

	As of December 31, 2020		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
		(In thousands)	
Assets			
Commodity derivative instruments	$21,156	($20,235)	$921
Contingent consideration arrangements	—	—	—
Fair value of derivatives - current	$21,156	($20,235)	$921
Commodity derivative instruments	$—	$—	$—
Contingent consideration arrangements	1,816	—	1,816
Other assets, net	$1,816	$—	$1,816
Liabilities			
Commodity derivative instruments	($117,295)	$20,235	($97,060)
Contingent consideration arrangements	—	—	—
Fair value of derivatives - current	($117,295)	$20,235	($97,060)
Commodity derivative instruments	$—	$—	$—
Contingent consideration arrangements	(8,618)	—	(8,618)
September 2020 Warrants liability	(79,428)	—	(79,428)
Fair value of derivatives - non current	($88,046)	$—	($88,046)

	As of December 31, 2019		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
		(In thousands)	
Assets			
Commodity derivative instruments	$26,849	($17,511)	$9,338
Contingent consideration arrangements	16,718	—	16,718
Fair value of derivatives - current	$43,567	($17,511)	$26,056
Commodity derivative instruments	$—	$—	$—
Contingent consideration arrangements	9,216	—	9,216
Other assets, net	$9,216	$—	$9,216
Liabilities			
Commodity derivative instruments	($38,708)	$17,511	($21,197)
Contingent consideration arrangements	(50,000)	—	(50,000)
Fair value of derivatives - current	($88,708)	$17,511	($71,197)
Commodity derivative instruments	($12,935)	—	($12,935)
Contingent consideration arrangements	(19,760)	—	(19,760)
Fair value of derivatives - non current	($32,695)	$—	($32,695)

The components of "(Gain) loss on derivative contracts" are as follows for the respective periods:

	Years Ended December 31,		
	2020	2019	2018
		(In thousands)	
(Gain) loss on oil derivatives	($48,031)	$73,313	($45,463)
(Gain) loss on natural gas derivatives	14,883	(8,889)	(3,081)
(Gain) loss on NGL derivatives	2,426	—	—
(Gain) loss on contingent consideration arrangements	2,976	(2,315)	—
(Gain) loss on September 2020 Warrants liability	55,519	—	—
(Gain) loss on derivative contracts	$27,773	$62,109	($48,544)

The components of "Cash (paid) received for commodity derivative settlements" and "Cash paid for settlements of contingent consideration arrangements, net" are as follows for the respective periods:

	Years Ended December 31,		
	2020	2019	2018
		(In thousands)	
Cash flows from operating activities			
Cash (paid) received on oil derivatives	$98,723	($11,188)	($27,510)
Cash (paid) received on natural gas derivatives	147	7,399	238
Cash (paid) received for commodity derivative settlements	$98,870	($3,789)	($27,272)
Cash flows from investing activities			
Cash paid for settlements of contingent consideration arrangements, net	($40,000)	$—	$—

Derivative positions

Listed in the tables below are the outstanding oil, natural gas and NGL derivative contracts as of December 31, 2020:

	For the Full Year of 2021	
Oil contracts (WTI)		
Swap contracts		
Total volume (Bbls)	1,827,000	
Weighted average price per Bbl	$43.54	
Collar contracts		
Total volume (Bbls)	10,282,775	
Weighted average price per Bbl		
Ceiling (short call)	$46.69	
Floor (long put)	$39.28	
Short call contracts		
Total volume (Bbls)	4,825,300	(1)
Weighted average price per Bbl	$63.62	
Short call swaption contracts		
Total volume (Bbls)	1,375,000	(2)
Weighted average price per Bbl	$49.01	
Oil contracts (ICE Brent)		
Swap contracts		
Total volume (Bbls)	848,300	
Weighted average price per Bbl	$37.36	
Collar contracts		
Total volume (Bbls)	730,000	
Weighted average price per Bbl		
Ceiling (short call)	$50.00	
Floor (long put)	$45.00	
Oil contracts (Midland basis differential)		
Swap contracts		
Total volume (Bbls)	3,022,900	
Weighted average price per Bbl	$0.26	
Oil contracts (Argus Houston MEH)		
Swap contracts		
Total volume (Bbls)	450,000	
Weighted average price per Bbl	$46.50	
Collar contracts		
Total volume (Bbls)	409,500	
Weighted average price per Bbl		
Ceiling (short call)	$47.00	
Floor (long put)	$41.00	

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

(2) The short call swaption contracts have exercise expiration dates as follows: 455,000 Bbls expire on March 31, 2021, 460,000 Bbls expire on June 30, 2021 and 460,000 Bbls expire on September 30, 2021.

Natural gas contracts (Henry Hub)	For the Full Year of 2021
Swap contracts	
Total volume (MMBtu)	11,123,000
Weighted average price per MMBtu	$2.60
Collar contracts (three-way collars)	
Total volume (MMBtu)	1,350,000
Weighted average price per MMBtu	
Ceiling (short call)	$2.70
Floor (long put)	$2.42
Floor (short put)	$2.00
Collar contracts (two-way collars)	
Total volume (MMBtu)	9,550,000
Weighted average price per MMBtu	
Ceiling (short call)	$3.04
Floor (long put)	$2.59
Short call contracts	
Total volume (MMBtu)	7,300,000 (1)
Weighted average price per MMBtu	$3.09
Natural gas contracts (Waha basis differential)	
Swap contracts	
Total volume (MMBtu)	16,425,000
Weighted average price per MMBtu	($0.42)

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

NGL contracts (OPIS Mont Belvieu Purity Ethane)	For the Full Year of 2021
Swap contracts	
Total volume (Bbls)	1,825,000
Weighted average price per Bbl	$7.62

Note 9 – Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair value of financial instruments

Cash, cash equivalents, and restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The carrying amount of borrowings outstanding under the Credit Facility approximates fair value as the borrowings bear interest at variable rates and are reflective of market rates. As of December 31, 2020, the Company determined that its Second Lien Notes met the requirements to be designated as Level 2 in the valuation hierarchy due to the availability of quoted secondary market trading prices resulting in the transfer out of Level 3. The following table presents the principal amounts of the Company’s Second Lien Notes and Senior Unsecured Notes with the fair values measured using quoted secondary market trading prices which are designated as Level 2 within the valuation hierarchy. See “Note 7 - Borrowings” for further discussion.

	December 31, 2020		December 31, 2019	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(In thousands)			
9.00% Second Lien Senior Secured Notes	$516,659	$470,160	$—	$—
6.25% Senior Notes	542,720	344,627	650,000	658,125
6.125% Senior Notes	460,241	260,036	600,000	611,130
8.25% Senior Notes	187,238	100,172	250,000	256,250
6.375% Senior Notes	320,783	161,995	400,000	405,424
Total	$2,027,641	$1,336,990	$1,900,000	$1,930,929

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis in the consolidated balance sheet. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using a third-party income approach valuation model that utilizes market-corroborated inputs that are observable over the term of the commodity derivative contract. The Company’s fair value calculations also incorporate an estimate of the counterparties’ default risk for commodity derivative assets and an estimate of the Company’s default risk for commodity derivative liabilities. As the inputs in the model are substantially observable over the term of the commodity derivative contract and there is a wide availability of quoted market prices for similar commodity derivative contracts, the Company designates its commodity derivative instruments as Level 2 within the fair value hierarchy. See “Note 8 - Derivative Instruments and Hedging Activities” for further discussion.

Contingent consideration arrangements - embedded derivative financial instruments. The embedded options within the contingent consideration arrangements are considered financial instruments under ASC 815. The Company engages a third-party valuation specialist using an option pricing model approach to measure the fair value of the embedded options on a recurring basis. The valuation includes significant inputs such as forward oil price curves, time to expiration, and implied volatility. The model provides for the probability that the specified pricing thresholds would be met for each settlement period, estimates undiscounted payouts, and risk adjusts for the discount rates inclusive of adjustments for each of the counterparty’s credit quality. As these inputs are substantially observable for the full term of the contingent consideration arrangements, the inputs are considered Level 2 inputs within the fair value hierarchy. See “Note 8 - Derivative Instruments and Hedging Activities” for further discussion.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2020 and 2019:

	December 31, 2020		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$921	$—
Contingent consideration arrangements	—	1,816	—
Liabilities			
Commodity derivative instruments	—	(97,060)	—
Contingent consideration arrangements	—	(8,618)	—
September 2020 Warrants	—	—	(79,428)
Total net assets (liabilities)	$—	($102,941)	($79,428)

	December 31, 2019		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$9,338	$—
Contingent consideration arrangements	—	25,934	—
Liabilities			
Commodity derivative instruments	—	(34,132)	—
Contingent consideration arrangements	—	(69,760)	—
Total net liabilities (liabilities)	$—	($68,620)	$—

September 2020 Warrants. The fair value of the September 2020 Warrants was calculated by a third-party valuation specialist using a Black-Scholes-Merton option pricing model. As historical volatility is a significant input into the model, the September 2020 Warrants are designated as Level 3 within the valuation hierarchy. See "Note 7 - Borrowings" and "Note 8 - Derivative Instruments and Hedging Activities" for additional details regarding the September 2020 Warrants.

The following table presents a reconciliation of the change in the fair value of the liability related to the September 2020 Warrants for the year ended December 31, 2020.

	Year Ended December 31, 2020
	(In thousands)
Beginning of period	$—
Recognition of issuance date fair value	23,909
(Gain) loss on changes in fair value	55,519
Transfers into (out of) Level 3	—
End of period	$79,428

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Acquisitions. The fair value of assets acquired and liabilities assumed, other than the contingent consideration arrangements which are discussed above, are measured as of the acquisition date by a third-party valuation specialist using a combination of income and market approaches, which are not observable in the market and are therefore designated as Level 3 inputs. Significant inputs include expected discounted future cash flows from estimated reserve quantities, estimates for timing and costs to produce and develop reserves, oil and natural gas forward prices, and a risk adjusted discount rate. See "Note 4 - Acquisitions and Divestitures" for additional discussion.

Asset retirement obligations. The Company measures the fair value of asset retirement obligations as of the date a well begins drilling or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 within the valuation hierarchy. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates. See "Note 14 - Asset Retirement Obligations" for additional discussion.

Note 10 – Share-Based Compensation

All share and per share numbers included in this footnote, except for those disclosed in "— 2018 Omnibus Incentive Plan" below, have been adjusted for the reverse stock split. See "Note 11 - Stockholders' Equity" for discussion of the reverse stock split and reduction in authorized shares.

2020 Omnibus Incentive Plan

At the Company's annual meeting of shareholders on June 8, 2020, shareholders approved the 2020 Omnibus Incentive Plan (the "2020 Plan"), which replaced the 2018 Omnibus Incentive Plan (the "2018 Plan"). From the effective date of the 2020 Plan, no further awards may be granted under the 2018 Plan, however, awards previously granted under the 2018 Plan will remain outstanding in accordance with their terms. Effective August 7, 2020, in connection with the reverse stock split and reduction in authorized shares, the Board of Directors approved and adopted an amendment to the 2020 Plan to proportionately adjust the limitations on awards that may be granted. At December 31, 2020, there were 2,002,463 shares available for future share-based awards under the 2020 Plan.

2018 Omnibus Incentive Plan

The 2018 Plan, which became effective May 10, 2018 following shareholder approval, authorized and reserved for issuance 9,400,000 shares of common stock, which may be issued upon exercise of vested stock options and/or the vesting of any other share-based equity award that is granted under this plan. The 2018 Plan replaced the 2011 Omnibus Incentive Plan (the "Prior Plan"), and included a provision at inception whereby all remaining, un-issued and authorized shares from the Prior Plan became issuable under the 2018 Plan. This transfer provision resulted in the transfer of an additional 1,322,742 shares into the 2018 Plan, increasing the quantity authorized and reserved for issuance under the 2018 Plan to 10,722,742 at the inception of the 2018 Plan. Another provision provided that shares, which would otherwise become available for issuance under the Prior Plan as a result of vesting and/or forfeiture of any equity awards existing as of the effective date of the 2018 Plan, would also increase the authorized shares available to the 2018 Plan. As a result of the Merger, the 2018 Plan was amended and restated to incorporate the 2017 Incentive Plan of Carrizo Oil & Gas, Inc. (the "Carrizo Plan"), including outstanding awards under the Carrizo Plan and shares available to grant to the former employees of Carrizo which were converted to shares of the Company by applying the conversion ratio of 1.75 shares of the Company per one share of Carrizo (the "Amended and Restated 2018 Plan").

RSU Equity Awards

The following table summarizes RSU Equity Award activity for the years ended December 31, 2020, 2019 and 2018:

	RSU Equity Awards (in thousands)	Weighted Average Grant-Date Fair Value per Share
For the Year Ended December 31, 2018		
Unvested at the beginning of the period	179	$115.36
Granted (1)	87	$144.86
Vested (2)	(51)	$103.83
Forfeited	(5)	$114.32
Unvested at the end of the period	210	$130.39
For the Year Ended December 31, 2019		
Unvested at the beginning of the period	210	$130.39
Granted (1)	188	$85.96
Vested (2)	(106)	$126.75
Forfeited	(23)	$110.55
Unvested at the end of the period	269	$102.48
For the Year Ended December 31, 2020		
Unvested at the beginning of the period	269	$102.48
Granted (1)	562	$21.07
Vested (2)	(132)	$105.14
Forfeited	(22)	$96.84
Unvested at the end of the period	677	$34.57

(1) Includes 111.2 thousand, 39.9 thousand and 20.8 thousand target performance-based RSU Equity Awards for the years ended December 31, 2020, 2019 and 2018, respectively.

(2) The fair value of shares vested was $1.6 million, $7.3 million and $6.3 million during the years ended December 31, 2020, 2019 and 2018, respectively.

Grant activity for the years ended December 31, 2020, 2019 and 2018 primarily consisted of RSU Equity Awards granted to executives and employees as part of the annual grant of long-term equity incentive awards.

The number of outstanding performance-based RSU Equity Awards that can vest is based on a calculation that compares the Company's total shareholder return ("TSR") to the same calculated return of a group of peer companies selected by the Company and can range between 0% and 300% of the target units for the awards granted in 2020 and between 0% and 200% of the target units for the awards granted in 2018 and 2019. The increase in the maximum amount of performance-based RSU Equity Awards that can vest for the awards granted in 2020 is due to an absolute TSR modifier, which was added as a second factor in the calculation, in addition to the relative TSR multiplier. While the absolute TSR modifier could increase the number of awards that vest, the number of awards that vest could also be reduced if the absolute TSR is less than 5% over the performance period.

The following table summarizes the shares that vested and did not vest as a result of the Company's performance as compared to its peers.

	Years Ended December 31,		
Performance-based Equity Awards	**2020**	**2019**	**2018**
Vesting Multiplier	50% - 100%	100%	142%
Target	21,920	8,878	8,300
Vested at end of performance period	11,372	8,878	11,786
Did not vest at end of performance period	10,548	—	—

The Company recognizes expense for performance-based RSU Equity Awards based on the fair value of the awards at the grant date. Awards with a performance-based provision do not allow for the reversal of previously recognized expense, even if the market metric is not achieved and no shares ultimately vest. For the years ended December 31, 2020, 2019 and 2018, the grant date fair value of the performance-based RSU Equity Awards, calculated using a Monte Carlo simulation, was $3.4 million, $4.3 million, and $3.5 million, respectively. The following table summarizes the assumptions used and the resulting grant date fair value per performance-based RSU Equity Award granted during the years ended December 31, 2020, 2019 and 2018:

Performance-based Awards	**June 29, 2020**	**January 31, 2020**	**January 31, 2019**	**May 10, 2018**
Expected term (in years)	2.5	2.9	2.9	2.6
Expected volatility	113.2%	54.8%	47.9%	51.6%
Risk-free interest rate	0.2%	1.3%	2.4%	2.6%
Dividend yield	—%	—%	—%	—%

As of December 31, 2020, unrecognized compensation costs related to unvested RSU Equity Awards were $13.5 million and will be recognized over a weighted average period of 1.7 years.

***Cash-Settled RSU* Awards**

The table below summarizes the Cash-Settled RSU Award activity for the years ended December 31, 2020, 2019 and 2018:

	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant-Date Fair Value per Share
For the Year Ended December 31, 2018		
Unvested at the beginning of the period	61	$123.82
Granted	35	$164.77
Vested	(28)	$116.67
Forfeited	(2)	$161.50
Unvested at the end of the period	66	$147.59
For the Year Ended December 31, 2019		
Unvested at the beginning of the period	66	$147.59
Granted	44	$105.08
Vested	(16)	$155.29
Forfeited	(8)	$145.71
Unvested at the end of the period	86	$124.22
For the Year Ended December 31, 2020		
Unvested at the beginning of the period	86	$124.22
Granted	142	$26.84
Vested	(16)	$160.39
Did not vest at end of performance period	(16)	$163.55
Forfeited	—	$—
Unvested at the end of the period	196	$47.56

Grant activity primarily consisted of Cash-Settled RSU Awards to executives as part of the annual grant of long-term equity incentive awards that occurred in the first half of each of the years presented in the table above. These awards cliff vest after an approximate three-year performance period.

The Company's outstanding Cash-Settled RSU Awards include the same performance-based vesting conditions as the performance-based RSU Equity Awards, which are described above. Additionally, the assumptions used to calculate the grant date fair value per Cash-Settled RSU Award granted for each of the respective periods presented are the same as the performance-based RSU Equity Awards presented above.

For the years ended December 31, 2020, 2019 and 2018, Cash-Settled RSU Awards vested resulting in cash payments of $0.2 million, $0.8 million and $3.2 million, respectively.

The following table summarizes the Company's liability for Cash-Settled RSU Awards and the classification in the consolidated balance sheets for the periods indicated:

	December 31,	
	2020	2019
	(In thousands)	
Other current liabilities	$182	$966
Other long-term liabilities	1,336	2,089
Total Cash-Settled RSU Awards	$1,518	$3,055

As of December 31, 2020, the Company had the following performance-based Cash-Settled RSU Awards outstanding:

	Target Awards Outstanding	Potential Minimum Units Vesting	Potential Maximum Units Vesting
		(In thousands)	
Vesting in 2021	35	—	70
Vesting in 2022	111	—	334
Other	50	50	50
Total Cash-Settled RSU Awards	196	50	454

As of December 31, 2020, unrecognized compensation costs related to unvested Cash-Settled RSU Awards were $1.5 million and will be recognized over a weighted average period of 1.9 years.

Cash-Settled SARs

As a result of the Merger, Cash SARs previously granted by Carrizo that were outstanding at closing of the Merger were canceled and converted into a Cash SAR covering shares of the Company's common stock, with the conversion calculated as prescribed in the agreement governing the Merger. The table below summarizes the Cash SAR activity for the year ended December 31, 2020.

	Stock Appreciation Rights (in thousands)	Weighted Average Exercise Prices	Weighted Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2019				
Outstanding, beginning of period	—	$—		
Granted	—	$—		
Reissued	368	$100.34		
Exercised	—	$—		
Forfeited	—	$—		
Expired	—	$—		
Outstanding, end of period	368	$100.34	4.4	$—
Vested, end of period	368	$100.34	—	$—
Vested and exercisable, end of period	—	$—	—	$—
For the Year Ended December 31, 2020				
Outstanding, beginning of period	368	$100.34		
Granted	—	$—		
Exercised	—	$—		
Forfeited	—	$—		
Expired	—	$—		
Outstanding, end of period	368	$100.34	3.4	$—
Vested, end of period	368	$100.34	—	$—
Vested and exercisable, end of period	—	$—	—	$—

The acquisition date fair value of the Cash SARs, calculated using the Black-Scholes-Merton option pricing model was $4.6 million. The following table summarizes the assumptions used, the resulting acquisition date fair value per Cash SAR, and the expiration dates for the grants that occurred during periods presented below:

	2019	2018	2017	2016
Expected term (in years)	5.4	4.5	1.9	1.1
Expected volatility	60.7%	56.9%	58.6%	68.1%
Risk-free interest rate	1.7%	1.7%	1.6%	1.5%
Dividend yield	—%	—%	—%	—%
Expiration date	March 17, 2026	March 17, 2025	March 23, 2022	March 17, 2021

The liabilities for Cash SARs as of December 31, 2020 and 2019 were $1.7 million and $5.0 million, respectively, all of which were classified as "Other current liabilities" in the consolidated balance sheets in the respective periods. Changes to the fair value of the Cash SARs are included in "General and administrative" in the consolidated statements of operations. As all Cash SARs are vested, there is no unrecognized compensation costs as of December 31, 2020.

Share-Based Compensation Expense, Net

Share-based compensation expense associated with the RSU Equity Awards, Cash-Settled RSU Awards, and Cash SARs, net of amounts capitalized, is included in "General and administrative" in the consolidated statements of operations. The following table presents share-based compensation expense (benefit), net for each respective period:

	Years Ended December 31,		
	2020	**2019**	**2018**
RSU Equity Awards	$13,030	$14,322	$9,460
Cash-Settled RSU Awards	(771)	1,021	336
Cash SARs	(3,344)	443	—
	8,915	15,786	9,796
Less: amounts capitalized to oil and gas properties	(6,252)	(4,704)	(3,434)
Total share-based compensation expense, net	$2,663	$11,082	$6,362

Note 11 – Stockholders' Equity

November 2020 Warrants

The Company issued approximately 1.75 million November 2020 Warrants in conjunction with the November 2020 Second Lien Notes that were issued in the senior unsecured note exchange described above. The Company determined that the November 2020 Warrants qualify as freestanding financial instruments, but meet the scope exception in ASC 815 - Derivatives and Hedging as they are indexed to the Company's common stock. As such, the November 2020 Warrants meet the applicable criteria for equity classification and are reflected in additional paid in capital in the consolidated balance sheets. See "Note 7 - Borrowings" and "Note 18 - Subsequent Events" for additional information.

Reverse Stock Split

On August 7, 2020, the Board of Directors effected a reverse stock split of the Company's outstanding shares of common stock at a ratio of 1-for-10 and reduced the total number of authorized shares of the Company's common stock pursuant to an amendment to the Company's Certificate of Incorporation, which was approved by the Company's shareholders at the Company's annual meeting of shareholders on June 8, 2020. The reverse stock split became effective as of the close of business on August 7, 2020. The Company's common stock began trading on a split-adjusted basis on the NYSE at the market open on August 10, 2020. The par value of the common stock was not adjusted as a result of the reverse stock split.

The reverse stock split was intended to, among other things, increase the per share trading price of the Company's common shares to satisfy the $1.00 minimum closing price requirement for continued listing on the NYSE. As a result of the reverse stock split, each 10 pre-split shares of common stock outstanding were automatically combined into one issued and outstanding share of common stock. The fractional shares that resulted from the reverse stock split were canceled by paying cash in lieu of the fair value. The number of outstanding shares of common stock were reduced from 397,479,684 as of August 7, 2020 to 39,746,967 shares. The total number of shares of common stock that the Company is authorized to issue was reduced from 525,000,000 to 52,500,000 shares. All share and per share amounts, except par value per share, in the accompanying consolidated financial statements and notes thereto were retroactively adjusted for all periods presented to give effect to this reverse stock split, including reclassifying an amount equal to the reduction in par value of common stock to additional paid-in capital in the current period.

10% Series A Cumulative Preferred Stock ("Preferred Stock")

On June 18, 2019, the Company announced it had given notice for the redemption (the "Redemption") of all outstanding shares of the Preferred Stock. On July 18, 2019 (the "Redemption Date"), the Preferred Stock were redeemed at a redemption price equal to $50.00 per share, plus an amount equal to all accrued and unpaid dividends in an amount equal to $0.24 per share, for a total redemption price of $50.24 per share or $73.0 million (the "Redemption Price"). The Company recognized an $8.3 million loss on the redemption due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value of the Preferred Stock. After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest. As such, no Preferred Stock dividends were paid during 2020. The Company paid Preferred Stock dividends of $4.0 million and $7.3 million for years ended December 31, 2019 and 2018, respectively.

Common Stock Offerings

On May 30, 2018, the Company completed an underwritten public offering of 25.3 million shares of its common stock for total estimated net proceeds (after the underwriter's discounts and offering costs) of approximately $288.0 million. The Company used proceeds from the offering to partially fund the Delaware Asset Acquisition completed in the third quarter of 2018. See "Note 4 - Acquisitions and Divestitures" for further discussion of the Delaware Asset Acquisition.

Note 12 – Income Taxes

The components of the Company's income tax expense are as follows:

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Current			
Federal	$—	$—	$—
State	3,447	220	—
Total current income tax expense	3,447	220	—
Deferred			
Federal	126,903	33,584	3,594
State	(8,296)	1,497	4,516
Total deferred income tax expense	118,607	35,081	8,110
Total income tax expense	$122,054	$35,301	$8,110

A reconciliation of the income tax expense calculated at the federal statutory rate of 21% to income tax expense is as follows:

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Income (loss) before income taxes	($2,411,567)	$103,229	$308,470
Income tax expense (benefit) computed at the statutory federal income tax rate	(506,429)	21,678	64,779
State income tax expense (benefit), net of federal benefit	(11,827)	1,253	3,568
Equity based compensation	2,746	1,222	(494)
Non-deductible compensation	—	90	1,209
Non-deductible merger expenses	—	5,537	—
Statutory depletion carryforward	—	5,381	—
Other	(1,621)	140	168
Change in valuation allowance	639,185	—	(61,120)
Income tax expense	$122,054	$35,301	$8,110

The income tax expense of $122.1 million for the year ended December 31, 2020 is primarily due to the valuation allowance recorded against the Company's net deferred tax assets. See "— Deferred Tax Asset Valuation Allowance" below for additional details.

At December 31, 2019, the Company recorded a tax expense of $5.5 million associated with non-deductible merger expenses from the Carrizo Acquisition which primarily relate to non-deductible executive compensation expenses and transaction costs that are inherently facilitative in nature and permanently capitalized for tax purposes.

As of December 31, 2020 and 2019, the net deferred income tax assets and liabilities are comprised of the following:

	As of December 31,	
	2020	2019
	(In thousands)	
Deferred tax assets		
Oil and natural gas properties	$431,142	$—
Federal net operating loss carryforward	141,308	110,703
Derivative asset	39,378	14,823
Operating lease right-of-use assets	8,567	29,897
Asset retirement obligations	10,134	9,981
Unvested RSU equity awards	1,962	4,928
Other	11,430	10,445
Total deferred tax assets	$643,921	$180,777
Deferred income tax valuation allowance	(639,185)	—
Net deferred tax assets	$4,736	$180,777
Deferred tax liability		
Oil and natural gas properties	$—	($38,546)
Derivative liability	—	—
Operating lease liabilities	(4,736)	(26,511)
Total deferred tax liability	($4,736)	($65,057)
Net deferred tax asset (liability)	$—	$115,720

Deferred Tax Asset Valuation Allowance

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company’s net deferred tax assets will be utilized prior to their expiration. A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at December 31, 2020, driven primarily by the impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the rest of 2020. This limits the ability to consider other subjective evidence such as the Company’s potential for future growth. Beginning in the second quarter of 2020 and continuing through the rest of 2020, based on the evaluation of the evidence available, the Company concluded that it is more likely than not that the net deferred tax assets will not be realized. As a result, the Company has recorded a valuation allowance of $639.2 million, reducing the net deferred tax assets as of December 31, 2020 to zero.

The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until the Company can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more future potential transactions. The valuation allowance does not preclude the Company from utilizing the tax attributes if the Company recognizes taxable income. As long as the Company continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company will have no significant deferred income tax expense or benefit.

Carrizo Acquisition

For federal income tax purposes, the Carrizo Acquisition qualified as a tax-free merger whereby the Company acquired carryover tax basis in Carrizo’s assets and liabilities. The Company recorded an opening balance sheet deferred tax asset of $162.6 million related to tax attributes acquired from Carrizo. The acquired income tax attributes primarily consist of future deductions related to oil and gas properties, derivative assets, and federal net operating losses (“NOLs”). The acquired NOLs are subject to an annual limitation under Internal Revenue Code Section 382, as described below, and the Company reduced the total NOL balance and associated deferred tax asset for the NOLs to the amount that was expected at that time to be fully utilized prior to expirations. See above for discussion of the valuation allowance against the Company’s net deferred tax assets.

Due to the issuance of common stock associated with the Carrizo acquisition, the Company incurred a cumulative ownership change and as such, the Company’s NOLs prior to the acquisition are subject to an annual limitation under Internal Revenue Code Section 382. At December 31, 2020, the Company had approximately $672.9 million of NOLs, including $284.1 million acquired from Carrizo. $414.9 million expire between 2035 and 2037 and $258.0 million have an indefinite carryforward life.

The Company had no significant unrecognized tax benefits at December 31, 2020. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. In the Company's major tax jurisdictions, the earliest year open to examination is 2016.

Note 13 – Leases

The Company determines if an arrangement is a lease at inception of the contract and, if the contract is determined to be a lease, classifies the lease as an operating or financing lease. The Company recognizes an operating or financing lease on its consolidated balance sheets as a lease liability, which represents the present value of the Company's obligation to make lease payments arising from the lease, with a related ROU asset, which represents the Company's right to use the underlying asset for the lease term. The Company's operating leases typically do not provide an implicit interest rate, therefore, the Company utilizes its incremental borrowing rate to calculate the present value of the lease payments based on information available at inception of the contract.

Lease expense for operating leases is recognized on a straight-line basis over the lease term. Lease expense for financing leases is comprised of interest expense on the financing lease liability and the amortization of the associated ROU asset, which is recognized on a straight-line basis over the lease term. Variable lease expense that is not dependent on an index or rate is not included in the operating or financing lease liability or ROU asset and is recognized in the period in which the obligation for those payments is incurred.

Types of Leases

The Company currently has leases associated with contracts for office space, drilling rigs, and the use of well equipment, vehicles, information technology infrastructure, and other office equipment, with the significant lease types described in more detail below.

Drilling Rigs. The Company enters into contracts for drilling rigs with third parties to support its development plan. These contracts are typically for one to three years and can be extended upon mutual agreement with the third party by providing written notice at least thirty days prior to the end of the primary contractual term. The Company exercises its discretion in choosing whether or not to extend these contracts on a drilling rig by drilling rig basis as a result of evaluating the conditions that exist at the time the contract expires, such as availability of drilling rigs and the Company's development plan. The Company has determined that it cannot conclude with reasonable certainty that it will choose to extend the contract past its primary term. As such, the Company uses the primary term in its calculation of the lease liability and ROU asset. The Company classifies its drilling rigs as operating leases and capitalizes the costs of the drilling rigs to oil and gas properties.

Office Space. The Company leases office space from third parties for its corporate office and certain field locations. These leases have non-cancelable terms between one to fifteen years. The Company has determined that it cannot conclude with reasonable certainty that it will exercise any option to extend the contract past the non-cancelable term. As such, the Company uses the non-cancelable term in its calculation of the lease liability and ROU asset. The Company classifies its leases for office space as operating leases with the costs recognized as "General and administrative" in its consolidated statements of operations.

Well Equipment. The Company rents compressors from third parties to facilitate the flow of production from its drilling operations to market. These contracts range from less than one year to three years for the primary term and continue thereafter on a month to month basis subject to cancellation by either party with thirty days' notice. The Company classifies the compressors as operating leases with a lease term equal to the primary term for those contracts that have a primary term greater than one year. After the primary term, each party has a substantive right to terminate the lease, therefore, enforceable rights and obligations do not exist subsequent to the primary term. For those contracts that are less than one year, the Company has concluded that they represent short-term operating leases and therefore, an operating lease liability and ROU asset is not recorded in the consolidated balance sheets. These lease payments are recognized as "Lease operating" in the Company's statements of operations.

The tables below, which present the components of lease costs and supplemental balance sheet information are presented on a gross basis. Other joint owners in the properties operated by the Company generally pay for their working interest share of costs associated with drilling rigs and well equipment.

The table below presents the components of the Company's lease costs for the year ended December 31, 2020.

	Years Ended December 31,	
	2020	2019
	(In thousands)	
Components of Lease Costs		
Finance lease costs	$1,489	$92
Amortization of right-of-use assets (1)	1,348	82
Interest on lease liabilities (2)	141	10
Operating lease cost (3)	46,888	38,076
Impairment of Operating lease ROU assets (4)	3,575	16,209
Short-term lease cost (5)	1,821	3,640
Variable lease costs (6)	259	—
Total lease costs	$54,032	$58,017

(1) Included as a component of "Depreciation, depletion and amortization" in the consolidated statements of operations.
(2) Included as a component of "Interest expense, net of capitalized amounts" in the consolidated statements of operations.
(3) For the years ended December 31, 2020 and 2019, approximately $34.2 million and $34.9 million, respectively, are costs associated with drilling rigs. These costs were capitalized to "Evaluated properties, net" in the consolidated balance sheets and the other remaining operating lease costs were components of "General and administrative" and "Lease operating" in the consolidated statements of operations.
(4) As a result of the downturn in economic conditions in conjunction with our ongoing effort to consolidate various office locations due to the Carrizo Acquisition, the Company evaluated certain of its office leases for impairment. Upon evaluation, the Company recorded impairments of certain of its Operating lease ROU assets for the years ended December 31, 2020 and 2019 of $3.6 million and $16.2 million, respectively, which are a component of "Merger and integration expenses" in the consolidated statements of operations.
(5) Short-term lease cost excludes expenses related to leases with a contract term of one month or less.
(6) Variable lease costs include additional payments that were not included in the initial measurement of the lease liability and related ROU asset for lease agreements with terms greater than 12 months. Variable lease costs primarily consist of incremental usage associated with drilling rigs.

The table below presents supplemental balance sheet information for the Company's operating leases. The Company's financing leases are immaterial.

	As of December 31,	
	2020	2019
	(In thousands)	
Leases		
Operating leases:		
Operating lease ROU assets	$22,526	$63,908
Current operating lease liabilities	$13,175	$42,858
Long-term operating lease liabilities	27,576	37,088
Total operating lease liabilities	$40,751	$79,946

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

	December 31, 2020
Weighted Average Remaining Lease Terms (In years)	
Operating leases	6.2
Financing leases	3.0
Weighted Average Discount Rate	
Operating leases	5.5%
Financing leases	6.7%

The table below presents the maturity of the Company's lease liabilities as of December 31, 2020.

	Operating Leases	Financing Leases
	(In thousands)	
2021	$14,918	$314
2022	5,443	250
2023	5,011	233
2024	4,936	39
2025	3,958	—
Thereafter	14,139	—
Total lease payments	48,405	836
Less imputed interest	(7,654)	(78)
Total lease liabilities	$40,751	$758

Note 14 – Asset Retirement Obligations

The table below summarizes the activity for the Company's asset retirement obligations:

	Years Ended December 31,	
	2020	2019
	(In thousands)	
Asset retirement obligations, beginning of period	$49,733	$14,292
Accretion expense	3,323	945
Liabilities incurred	3,895	615
Increase due to acquisition of oil and gas properties	—	26,107
Liabilities settled	(2,220)	(3,394)
Dispositions	(351)	(1,776)
Revisions to estimates	4,710	12,944
Asset retirement obligations, end of period	59,090	49,733
Less: Current asset retirement obligations	(1,881)	(873)
Non-current asset retirement obligations	$57,209	$48,860

Certain of the Company's operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the consolidated balance sheets at December 31, 2020 and 2019 as long-term restricted investments were $3.5 million, and are presented in "Other assets, net." These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 15 – Accounts Receivable, Net

	As of December 31,	
	2020	2019
	(In thousands)	
Oil and natural gas receivables	$100,257	$165,275
Joint interest receivables	11,530	39,114
Other receivables	24,191	6,610
Total	135,978	210,999
Allowance for credit losses	(2,869)	(1,536)
Total accounts receivable, net	$133,109	$209,463

Note 16 – Accounts Payable and Accrued Liabilities

	As of December 31,	
	2020	2019
	(In thousands)	
Accounts payable	$101,231	$217,578
Revenues payable	162,762	145,816
Accrued capital expenditures	32,493	61,950
Accrued interest	45,033	36,295
Accrued severance (1)	3,846	28,803
Total accounts payable and accrued liabilities	$345,365	$490,442

(1) See "Note 4 - Acquisitions and Divestitures" for further information regarding the Carrizo Acquisition.

Note 17 – Commitments and Contingencies

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability hereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment are not expected to have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies hereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

The table below presents total minimum commitments associated with long-term, non-cancelable leases, drilling rig contracts and gathering, processing and transportation service agreements, which require minimum volumes of oil, natural gas, or produced water to be delivered, as of December 31, 2020.

	2021	2022	2023	2024	2025	2026 and Thereafter	Total
				(In thousands)			
Operating leases (1)	$10,601	$5,443	$5,011	$4,936	$3,958	$14,139	$44,088
Drilling rig contracts (2)	4,317	—	—	—	—	—	4,317
Delivery commitments (3)	12,401	10,980	11,553	12,451	12,417	39,291	99,093
Produced water disposal commitments (4)	21,355	18,320	10,775	7,975	4,267	741	63,433
Total	$48,674	$34,743	$27,339	$25,362	$20,642	$54,171	$210,931

(1) Operating leases primarily consist of contracts for office space. See "Note 13 – Leases" for additional information.

(2) Drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will generally be billed for their working interest share of such costs. In January 2021, the Company extended one of its drilling rig contracts for a term of one year. The gross contractual obligation for this extended drilling rig contract is approximately $5.5 million and is not included in the table above as it was entered into subsequent to December 31, 2020.

(3) Delivery commitments represent contractual obligations the Company has entered into for certain gathering, processing and transportation service agreements which require minimum volumes of oil or natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any oil or natural gas.

(4) Produced water disposal commitments represent contractual obligations the Company has entered into for certain service agreements which require minimum volumes of produced water to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water.

Operating leases

As of December 31, 2020, the Company had contracts for two horizontal drilling rigs. The contract terms will end on various dates between March 2021 and May 2021.

Other commitments

The following table includes the Company's current oil sales contracts and firm transportation agreements as of December 31, 2020:

Type of Commitment [1]	Region	Execution Date	Start Date	End Date	Committed Volumes (Bbls/d)
Oil sales contract	Eagle Ford	November 2020	January 2021	December 2021	10,000
Oil sales contract	Permian	August 2020	August 2020	December 2021	7,500
Oil sales contract	Permian	July 2019	August 2021	July 2026	5,000
Oil sales contract	Permian	June 2019	January 2020	December 2024	10,000
Oil sales contract	Permian	August 2018	April 2020	March 2022	15,000
Firm transportation agreement [2][3]	Permian	June 2019	August 2020	July 2030	10,000
Firm transportation agreement [2]	Permian	August 2018	April 2020	March 2027	15,000

(1) For each of the commitments shown in the table above, the committed barrels may include volumes produced by the Company and other third-party working, royalty, and overriding royalty interest owners whose volumes the Company markets on their behalf.
(2) Each of the firm transportation agreements shown in the table above grant the Company access to delivery points in several locations along the Gulf Coast.
(3) The committed volumes shown in the table above for this particular firm transportation agreement are average volumes. For the terms of August 2020-July 2023, August 2023-July 2027 and August 2027-July 2030, the committed volumes are 7,500 Bbls/d, 10,000 Bbls/d and 12,500 Bbls/d, respectively.

Note 18 – Subsequent Events (Unaudited)

Hedging

Subsequent to December 31, 2020, the Company entered into the following derivative contracts:

Oil contracts (WTI)	For the Full Year of 2021	For the Full Year of 2022	
Collar contracts			
Total volume (Bbls)	920,000	1,355,000	
Weighted average price per Bbl			
Ceiling (short call)	$60.18	$60.00	
Floor (long put)	$47.50	$45.00	
Short call swaption contracts [1]			
Total volume (Bbls)	—	1,825,000	(2)
Weighted average price per Bbl	$—	$52.18	

(1) In February 2021, the Company terminated a total of 920,000 Bbls of short call swaption contracts for the second half of 2021 and simultaneously executed the full year 2022 short call swaption contracts shown in the table above.
(2) The short call swaption contracts shown in the table above have exercise expiration dates of December 31, 2021.

Natural gas contracts (Henry Hub)	For the Full Year of 2022
Collar contracts (two-way collars)	
Total volume (MMBtu)	1,800,000
Weighted average price per MMBtu	
Ceiling (short call)	$3.88
Floor (long put)	$2.78

Additionally, in January 2021, the Company paid approximately $3.1 million to terminate 184,000 Bbls of crude ICE Brent swaps. In February 2021, the Company executed offsetting crude ICE Brent swaps on 159,300 Bbls, resulting in a locked-in loss of approximately $2.9 million which the Company will pay as the applicable contracts settle.

Exercise of Warrants

In January and February 2021, certain entities that were issued September 2020 Warrants and November 2020 Warrants provided notice and exercised their outstanding warrants. As a result of these exercises, the Company issued a total of 6.4 million shares of its common stock in exchange for 8.4 million outstanding warrants determined on a net share settlement basis. The exercise of the September 2020 Warrants also resulted in settlement of the associated derivative liability which at December 31, 2020 was $79.4 million.

Note 19 - Supplemental Information on Oil and Natural Gas Operations (Unaudited)

Estimated Reserves

For each year in the table below, the estimated proved reserves were prepared by DeGolyer and MacNaughton ("D&M"), Callon's independent third party reserve engineers, with the exception of the estimated proved reserves in 2019 obtained as a result of the Carrizo Acquisition, which were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), the independent third party reserve engineers historically retained by Carrizo. The reserves were prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only, and should not be deemed exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and natural gas properties or the cost that would be incurred to obtain equivalent reserves.

Extrapolation of performance history and material balance estimates were utilized by the Company's both D&M and Ryder Scott to project future recoverable reserves for the producing properties where sufficient history existed to suggest performance trends and where these methods were applicable to the subject reservoirs. The projections for the remaining producing properties were necessarily based on volumetric calculations and/or analogy to nearby producing completions. Reserves assigned to nonproducing zones and undeveloped locations were projected on the basis of volumetric calculations and analogy to nearby production, and to a small extent, horizontal PDP and PUD categories.

The following tables disclose changes in the estimated quantities of proved reserves, all of which are located onshore within the continental United States:

	Years Ended December 31,		
Proved reserves	**2020**	**2019**	**2018**
Oil (MBbls)			
Beginning of period	346,361	180,097	107,072
Purchase of reserves in place	—	183,382	30,756
Sales of reserves in place	(9,673)	(17,980)	—
Extensions and discoveries	25,678	45,663	67,763
Revisions to previous estimates	(49,336)	(33,136)	(16,051)
Production	(23,543)	(11,665)	(9,443)
End of period	289,487	346,361	180,097
Natural Gas (MMcf)			
Beginning of period	757,134	350,466	179,410
Purchase of reserves in place	—	455,158	53,563
Sale of reserves in place	(20,389)	(86,856)	—
Extensions and discoveries	44,282	82,566	103,149
Revisions to previous estimates	(198,628)	(24,482)	29,791
Production	(40,801)	(19,718)	(15,447)
End of period	541,598	757,134	350,466
NGLs (MBbls)			
Beginning of period	67,462	—	—
Purchase of reserves in place	—	67,597	—
Sale of reserves in place	(3,049)	—	—
Extensions and discoveries	8,349	—	—
Revisions to previous estimates	30,214	—	—
Production	(6,850)	(135)	—
End of period	96,126	67,462	—
Total (MBoe)			
Beginning of period	540,012	238,508	136,974
Purchase of reserves in place	—	326,838	39,683
Sale of reserves in place	(16,120)	(32,456)	—
Extensions and discoveries	41,407	59,424	84,955
Revisions to previous estimates	(52,227)	(37,216)	(11,086)
Production	(37,193)	(15,086)	(12,018)
End of period	475,879	540,012	238,508

Proved developed reserves	2020	2019	2018
	Years Ended December 31,		
Oil (MBbls)			
Beginning of period	152,687	92,202	51,920
End of period	128,923	152,687	92,202
Natural gas (MMcf)			
Beginning of period	320,676	218,417	104,389
End of period	238,119	320,676	218,417
NGLs (MBbls)			
Beginning of period	24,844	—	—
End of period	43,315	24,844	—
Total proved developed reserves (MBoe)			
Beginning of period	230,977	128,605	69,318
End of period	211,925	230,977	128,605
Proved undeveloped reserves			
Oil (MBbls)			
Beginning of period	193,674	87,895	55,152
End of period	160,564	193,674	87,895
Natural gas (MMcf)			
Beginning of period	436,458	132,049	75,021
End of period	303,479	436,458	132,049
NGLs (MBbls)			
Beginning of period	42,618	—	—
End of period	52,811	42,618	—
Total proved undeveloped reserves (MBoe)			
Beginning of period	309,035	109,903	67,656
End of period	263,954	309,035	109,903
Total proved reserves			
Oil (MBbls)			
Beginning of period	346,361	180,097	107,072
End of period	289,487	346,361	180,097
Natural gas (MMcf)			
Beginning of period	757,134	350,466	179,410
End of period	541,598	757,134	350,466
NGLs (MBbls)			
Beginning of period	67,462	—	—
End of period	96,126	67,462	—
Total proved reserves (MBoe)			
Beginning of period	540,012	238,508	136,974
End of period	475,879	540,012	238,508

Total Proved Reserves

For the year ended December 31, 2020, the Company's net decrease in proved reserves of 64.1 MMBoe was primarily due to the following:

- Increase of 41.4 MMBoe through extensions and discoveries through our development efforts in our operating areas, of which 11.7 MMBoe were proved developed reserves;
- Decrease of 52.2 MMBoe for revisions of previous estimates that were primarily comprised of:
    - 26.2 MMBoe reduction due to the change in 12-Month Average Realized Price of crude oil which decreased by approximately 31% as compared to December 31, 2019. Included in the decrease are 2.1 MMBoe associated with proved developed producing wells and 0.8 MMBoe associated with proved undeveloped wells that were no longer economic at December 31, 2020 as a result of the decrease in the 12-Month Average Realized Price of crude oil;

    - 24.2 MMBoe reduction due to anticipated hydrocarbon recoveries resulting from observed well performance over longer production timeframes during the testing of various full field development plan concepts;
    - 24.0 MMBoe reduction due to PUDs that were removed primarily as a result of changes in anticipated well densities as the Company develops its properties in an effort to increase capital efficiency and cash flow generation;
    - 14.7 MMBoe increase due to the volumetric impact from presenting NGLs and natural gas separately due to the modification of certain of the Company's natural gas processing agreements which allow it to take title to NGLs resulting from the processing of its natural gas subsequent to January 1, 2020. For periods prior to January 1, 2020, except for reserve volumes specifically associated with Carrizo, the Company presented its reserve volumes for NGLs with natural gas;
    - 7.5 MMBoe increase due to reduced assumptions for operational expenses as the Company continues to improve its field practices during the integration of the properties acquired from Carrizo;
- Decrease of 16.1 MMBoe for sales of reserves in place primarily associated with the ORRI Transaction and the sale of substantially all of the Company's non-operated assets; and
- Decrease of 37.2 MMBoe for production.

For the year ended December 31, 2019, the Company's net increase in proved reserves of 301.5 MMBoe was primarily due to the following:

- Increase of 326.8 MMBoe for purchases of reserves in place related to the acquisition of Carrizo Oil & Gas, Inc. in late 2019;
- Increase of 59.4 MMBoe through extensions and discoveries through our development efforts in our operating areas, of which 17.1 MMBoe were proved developed reserves;
- Decrease of 32.5 MMBoe as a result of sales of reserves in place, primarily associated with our Ranger Divestiture which totaled 27.1 MMBoe;
- Decrease of 37.2 MMBoe for revisions of previous estimates that were primarily comprised of:
    - 21.7 MMBoe reduction due to the observed impact of well spacing tests on producing wells and the related impact on PUD reserve estimates, primarily in the Midland Basin, as the Company advances larger scale development concepts across its multi-zone inventory;
    - 9.8 MMBoe reduction due to reclassifications of PUDs within the Company's development plans, primarily related to certain fields within the Company's Delaware Basin acreage, that were moved outside of the five-year development window primarily driven by the acquisition of Carrizo Oil & Gas, Inc. in December 2019, which afforded us the opportunity to reallocate capital across the combined portfolio in an effort to increase capital efficiency through larger scale development concepts as well as preserve our co-development philosophy to optimize resource capture from multiple zones;
    - 5.7 MMBoe reduction due to pricing; and
- Decrease of 15.1 MMBoe for production.

For the year ended December 31, 2018, the Company's net increase in proved reserves of 101.5 MMBoe was primarily due to the following:

- Increase of 85.0 MMBoe through extensions and discoveries, 28.2 MMBoe of which were proved developed reserves, as a result of development efforts in the Permian where the Company drilled 70 gross (57.5 net) wells;
- Increase of 39.7 MMBoe for purchases of reserves in place, of which 29.8 MMBoe were proved developed reserves, primarily related to the Company's acquisition from Cimarex Energy Company in August 2018;
- Decrease of 11.1 MMBoe for revisions of previous estimates that were primarily comprised of:
    - 9.1 MMBoe reduction due to reclassifications of PUDs within the Company's development plans that were moved outside of the five-year development window primarily driven by larger pad development concepts and co-development of zones;
    - 2.0 MMBoe related to technical revisions of PUDs; and
- Decrease of 12.0 MMBoe for production.

Capitalized Costs

Capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	As of December 31,	
	2020	2019
Oil and natural gas properties:	(In thousands)	
Evaluated properties	$7,894,513	$7,203,482
Unevaluated properties	1,733,250	1,986,124
Total oil and natural gas properties	9,627,763	9,189,606
Accumulated depreciation, depletion, amortization and impairment	(5,538,803)	(2,520,488)
Total oil and natural gas properties capitalized	$4,088,960	$6,669,118

Costs Incurred

Costs incurred in oil and natural gas property acquisitions, exploration and development activities are as follows:

	Years Ended December 31,		
	2020	2019	2018
Acquisition costs:		(In thousands)	
Evaluated properties	$—	$49,572	$347,305
Unevaluated properties	30,696	107,347	466,816
Development costs	379,900	189,259	259,410
Exploration costs	122,865	309,013	323,458
Total costs incurred	$533,461	$655,191	$1,396,989

Standardized Measure

The following tables present the standardized measure of future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2020. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and natural gas reserves. Proved reserve estimates and future cash flows are based on the average realized prices for sales of oil, natural gas, and NGLs on the first calendar day of each month during the year. The following average realized prices were used in the calculation of proved reserves and the standardized measure of discounted future net cash flows.

	Years Ended December 31,		
	2020	2019	2018
Oil ($/Bbl)	$37.44	$53.90	$58.40
Natural gas ($/Mcf)	$1.02	$1.55	$3.64
NGLs ($/Bbl)	$11.10	$15.58	$—

Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

	Standardized Measure For the Year Ended December 31,		
	2020	2019	2018
		(In thousands)	
Future cash inflows	$12,458,033	$20,891,469	$11,794,080
Future costs			
Production	(5,433,496)	(6,717,088)	(2,923,959)
Development and net abandonment	(2,204,301)	(3,058,861)	(1,429,787)
Future net inflows before income taxes	4,820,236	11,115,520	7,440,334
Future income taxes	(65,405)	(941,768)	(782,470)
Future net cash flows	4,754,831	10,173,752	6,657,864
10% discount factor	(2,444,441)	(5,222,726)	(3,716,571)
Standardized measure of discounted future net cash flows	$2,310,390	$4,951,026	$2,941,293

	Changes in Standardized Measure For the Year Ended December 31,		
	2020	2019	2018
		(In thousands)	
Standardized measure at the beginning of the period	$4,951,026	$2,941,293	$1,556,682
Sales and transfers, net of production costs	(649,781)	(579,744)	(481,306)
Net change in sales and transfer prices, net of production costs	(2,719,579)	(387,970)	222,802
Net change due to purchases of in place reserves	—	2,975,296	554,697
Net change due to sales of in place reserves	(202,928)	(303,526)	—
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	250,759	607,146	1,001,873
Changes in future development cost	361,008	205,398	40,483
Previously estimated development costs incurred	318,470	134,037	91,900
Revisions of quantity estimates	(671,800)	(420,488)	(167,096)
Accretion of discount	536,958	314,921	157,676
Net change in income taxes	383,999	(210,641)	(187,841)
Changes in production rates, timing and other	(247,742)	(324,696)	151,423
Aggregate change	(2,640,636)	2,009,733	1,384,611
Standardized measure at the end of period	$2,310,390	$4,951,026	$2,941,293

Note 20 - Supplemental Quarterly Financial Information (Unaudited)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2020 and 2019:

2020	First Quarter (3)	Second Quarter (4)	Third Quarter (5)	Fourth Quarter (6)
	(In thousands, except per share amounts)			
Total operating revenues	$289,919	$157,234	$290,026	$295,968
Income (loss) from operations	47,860	(1,361,676)	(629,707)	(513,329)
Net income (loss)	216,565	(1,564,731)	(680,384)	(505,071)
Income (loss) available to common stockholders	216,565	(1,564,731)	(680,384)	(505,071)
Income (loss) available to common stockholders per common share (1)(2)				
Basic	$5.46	($39.41)	($17.12)	($12.71)
Diluted	$5.46	($39.41)	($17.12)	($12.71)

2019	First Quarter (7)	Second Quarter (8)	Third Quarter (9)	Fourth Quarter (10)
	(In thousands, except per share amounts)			
Total operating revenues	$153,047	$167,052	$155,378	$196,095
Income from operations	43,225	58,509	52,544	18,380
Net income (loss)	(19,543)	55,180	55,834	(23,543)
Income (loss) available to common stockholders	(21,367)	53,357	47,180	(23,543)
Income (loss) available to common stockholders per common share (1) (2)				
Basic	($0.94)	$2.34	$2.07	($0.95)
Diluted	($0.94)	$2.34	$2.07	($0.95)

(1) The sum of quarterly income (loss) available to common stockholders per common share does not agree with the total year income (loss) available to common stockholders per common share as each computation is based on the weighted average of common shares outstanding during the period.

(2) Income (loss) available to common stockholders per common share has been retroactively adjusted to reflect the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 - Stockholders' Equity" for additional information.

(3) First quarter of 2020 included the following:
  a. $252.0 million gain on derivative contracts
  b. $15.8 million of merger and integration expenses associated with the merger with Carrizo

(4) Second quarter of 2020 included the following:
  a. $1.3 billion impairment of evaluated oil and gas properties
  b. $127.0 million loss on derivative contracts
  c. $8.1 million of merger and integration expenses associated with the merger with Carrizo

(5) Third quarter of 2020 included the following:
  a. $685.0 million impairment of evaluated oil and gas properties
  b. $27.0 million loss on derivative contracts
  c. $2.5 million of merger and integration expenses associated with the merger with Carrizo

(6) Fourth quarter of 2020 included the following:
  a. $585.8 million impairment of evaluated oil and gas properties
  b. $125.7 million loss on derivative contracts
  c. $1.6 million of merger and integration expenses associated with the merger with Carrizo
  d. $170.4 million gain on extinguishment of debt

(7) First quarter of 2019 included the following:
  a. $67.3 million loss on derivative contracts

(8) Second quarter of 2019 included the following:
  a. $14.0 million gain on derivative contracts

(9) Third quarter of 2019 included the following:
  a. $21.8 million gain on derivative contracts
  b. $5.9 million of merger and integration expenses associated with the merger with Carrizo
  c. $8.3 million loss on redemption of Preferred Stock

(10) Fourth quarter of 2019 included the following:
  a. Activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.
  b. $68.4 million of merger and integration expenses associated with the merger with Carrizo
  c. $30.7 million loss on derivative contracts
  d. $4.9 million loss on extinguishment of debt

ITEM 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2020.

Management's report on internal control over financial reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control structure is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles. Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2020 based on the framework in *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission (2013 framework) (the COSO criteria). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2020.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm, Grant Thornton, LLP, has issued an attestation report regarding its assessment of the Company's internal control over financial reporting as of December 31, 2020, presented preceding the Company's financial statements included in Part II, Item 8 of this 2020 Annual Report on Form 10-K. Additionally, the financial statements for the years ended December 31, 2019 and 2018, covered in this 2020 Annual Report on Form 10-K, have also been audited by the Company's independent registered public accounting firm, whose report is presented preceding the their report on the Company's internal control over financial reporting, included in Part II, Item 8.

Changes in internal control over financial reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

ITEM 9B. Other Information

None.

PART III.

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the definitive proxy statement (the "2021 Proxy Statement") for our 2021 annual meeting of shareholders. The 2021 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

The Company has adopted a code of ethics that applies to the Company's officers, directors, employees, agents and representatives and includes a code of ethics for senior financial officers that applies to the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics has been posted on the Company's website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at mailing address 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

ITEM 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

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

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

ITEM 14. Principal Accountant Fees and Services

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

PART IV.

ITEM 15. Exhibits

The following is an index to the financial statements and financial statement schedules that are filed in Part II, Item 8 of this report on Form 10-K.

Exhibit Number		Description	Incorporated by reference (File No. 001-14039, unless otherwise indicated) Form	Exhibit	Filing Date
2.1	(d)	Purchase and Sale Agreement, dated May 23, 2018, between Cimarex Energy Co, Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. and Callon Petroleum Operating Company	8-K	2.1	05/24/2018
2.2	(d)	Purchase and Sale Agreement between Callon Petroleum Operating Company and Sequitur Permian, LLC dated April 8, 2019	8-K	2.1	06/13/2019
2.3	(d)	Agreement and Plan of Merger, dated as of July 14, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	8-K	2.1	07/15/2019
2.4		Amendment No. 1 to Agreement and Plan of Merger, dated August 19, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	10-Q	2.2	11/05/2019
2.5		Amendment No. 2 to Agreement and Plan of Merger, dated November 13, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	8-K	2.1	11/14/2019
3.1		Certificate of Incorporation of the Company, as amended through May 12, 2016	10-Q	3.1	11/03/2016
3.2		Certificate of Amendment to the Certificate of Incorporation of Callon, effective December 20, 2019	8-K	3.1	12/20/2019
3.3		Certificate of Amendment to the Certificate of Incorporation of Callon, effective August 7, 2020	8-K	3.1	08/07/2020
3.4		Amended and Restated Bylaws of the Company	10-K	3.2	02/27/2019
4.1		Specimen Common Stock Certificate	10-K	4.1	02/28/2018
4.2	(a)	Description of Common Stock			
4.3		Indenture of 6.125% Senior Notes Due 2024, dated as of October 3, 2016, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee	8-K	4.1	10/04/2016
4.4		First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and U.S. Bank National Association, as trustee	8-K	4.3	12/20/2019
4.5		Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated October 3, 2016, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.2	10/04/2016
4.6		Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated May 24, 2017, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.1	05/24/2017
4.7		Indenture of 6.375% Senior Notes Due 2026, dated as of June 7, 2018, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee	8-K	4.1	06/07/2018
4.8		First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and U.S. Bank National Association, as trustee	8-K	4.4	12/20/2019
4.9		Registration Rights Agreement of 6.375% Senior Notes Due 2026, dated June 7, 2018, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.2	06/07/2018
4.10		Indenture, dated May 28, 2008, among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.1	05/28/2008
4.11		Sixteenth Supplemental Indenture, dated April 28, 2015, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	04/28/2015
4.12		Eighteenth Supplemental Indenture, dated May 20, 2015, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	05/22/2015
4.13		Twentieth Supplemental Indenture, dated July 14, 2017, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	07/14/2017
4.14		Twenty-First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K	4.1	12/20/2019
4.15		Twenty-Second Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K	4.2	12/20/2019
4.16		Warrant Agreement, dated as of December 20, 2019, between Callon and American Stock Transfer And Trust Company, LLC, as warrant agent	8-K	4.5	12/20/2019
4.17		Indenture among the Company, the guarantors named therein and U.S. Bank National Association, as trustee and collateral agent, dated September 30, 2020	8-K	4.1	10/01/2020

4.18		Registration Rights Agreement between the Company and Chambers Investments, LLC, dated September 30, 2020	8-K	4.2	10/01/2020
4.19		Warrant Agreement between the Company and American Stock Transfer and Trust Company, LLC, as warrant agent, dated September 30, 2020	8-K	4.3	10/01/2020
10.1	(d)	Credit Agreement, dated December 20, 2019, among Callon, JPMorgan Chase Bank, National Association, as administrative agent, and the lenders party thereto	8-K	10.1	12/20/2019
10.2	(d)	First Amendment to Credit Agreement among Callon, JPMorgan Chase Bank, N.A., as administrative agent, the guarantors party thereto and the lender parties thereto, dated May 7, 2020	10-Q	10.1	05/11/2020
10.3		Second Amendment to Credit Agreement among Callon, JPMorgan Chase Bank, N.A., as administrative agent, the guarantors party thereto and the lender parties thereto, dated September 30, 2020	8-K	10.2	10/01/2020
10.4		Third Amendment to Credit Agreement among Callon, JPMorgan Chase Bank, N.A., as administrative agent, the guarantors party thereto and the lender parties thereto, dated September 30, 2020	8-K	10.3	10/01/2020
10.5	(b)	Amended and Restated Deferred Compensation Plan for Outside Directors - Callon Petroleum Company, dated as of May 10, 2017 and effective as of May 1, 2017	10-K	10.11	02/28/2018
10.6	(b)	Callon Petroleum Company 2018 Omnibus Incentive Plan	DEF 14A	A	03/23/2018
10.7	(b)	Amended and Restated 2018 Omnibus Incentive Plan	10-K	10.7	02/27/2020
10.8	(b)	Form of Callon Petroleum Company Director Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.4	08/07/2018
10.9	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.5	08/07/2018
10.10	(b)	Form of Change in Control Severance Compensation Agreement, dated as of January 1, 2019, by and between Callon Petroleum Company and its executive officers	10-K	10.17	02/27/2019
10.11	(b)	Change in Control Severance Compensation Agreement, dated as of January 1, 2019, by and between Joseph C. Gatto, Jr., and Callon Petroleum Company	10-K	10.18	02/27/2019
10.12	(b)	Carrizo Oil & Gas, Inc. Change in Control Severance Plan effective February 14, 2019	10-K(File No. 000-29187-87)	10.15	03/01/2019
10.13	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.20	02/27/2019
10.14	(b)	Form of Callon Petroleum Officer Cash-Settleable Performance Share Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.21	02/27/2019
10.15	(b)	Form of Callon Petroleum Company Officer Stock-Settleable Performance Share Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.22	02/27/2019
10.26	(b)	Form of Callon Petroleum Company Officer Restricted Stock Unit Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.23	02/27/2019
10.17	(b)	2017 Incentive Plan of Carrizo Oil &Gas, Inc.	8-K(File No. 000-29187-87)	10.1	05/16/2019
10.18	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan	10-K	10.22	02/27/2020
10.19	(b)	Form of Callon Petroleum Officer Cash-Settleable Performance Share Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan	10-K	10.23	02/27/2020
10.20	(b)	Form of Callon Petroleum Company Officer Stock-Settleable Performance Share Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan	10-K	10.24	02/27/2020
10.21	(b)	Form of Callon Petroleum Company Officer Restricted Stock Unit Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan	10-K	10.25	02/27/2020
10.22	(b)	Callon Petroleum Company 2020 Omnibus Incentive Plan	DEF 14A	B	04/28/2020
10.23	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on June 8, 2020, under the 2020 Omnibus Incentive Plan	10-Q	10.3	08/05/2020
10.24	(b)	Form of Callon Petroleum Company Director Restricted Stock Unit Award Agreement, adopted on June 8, 2020, under the 2020 Omnibus Incentive Plan	10-Q	10.4	08/05/2020
10.25	(b)	Form of Callon Petroleum Company Officer Cash Retention Award Agreement, adopted on September 30, 2020, under the 2020 Omnibus Incentive Plan	10-Q	10.4	11/03/2020
10.26	(b)	Form of Callon Petroleum Company Officer Cash Incentive Award Agreement, adopted on September 30, 2020, under the 2020 Omnibus Incentive Plan	10-Q	10.5	11/03/2020
10.27	(d)	Purchase Agreement among the Company, Chambers Investments, LLC and the guarantors named therein, dated September 30, 2020	8-K	10.1	10/01/2020
10.28	(a)(d)	Exchange Agreement among the Company and the holders of the Company's senior notes party thereto, dated November 2, 2020			
10.29	(a)(b)	Deferred Compensation Plan for Outside Directors, as Amended and Restated as of January 1, 2021			
21.1	(a)	Subsidiaries of the Company			
22.1	(a)	Subsidiary Guarantors			
23.1	(a)	Consent of Grant Thornton LLP			

23.2	(a)	Consent of DeGolyer and MacNaughton, Inc.
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)
32.1	(c)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)
99.1	(a)	Reserve Report Summary prepared by DeGolyer and MacNaughton, Inc. as of December 31, 2020
101.INS	(a)	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	(a)	Inline XBRL Taxonomy Extension Schema Document
101.CAL	(a)	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	(a)	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	(a)	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	(a)	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	(a)	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

(a) Filed herewith.
(b) Indicates management compensatory plan, contract, or arrangement.
(c) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.
(d) Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. Callon agrees to furnish a supplemental copy of any omitted schedule or attachment to the SEC upon request.

ITEM 16. Form 10-K Summary

None.

SIGNATURES

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

Callon Petroleum Company

/s/ James P. Ulm, II — Date: February 25, 2021
By: James P. Ulm, II
Chief Financial Officer (principal financial officer)

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

/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr. (principal executive officer)	Date: February 25, 2021
/s/ James P. Ulm, II James P. Ulm, II (principal financial officer)	Date: February 25, 2021
/s/ Gregory F. Conaway Gregory F. Conaway (principal accounting officer)	Date: February 25, 2021
/s/ L. Richard Flury L. Richard Flury (chairman of the board of directors)	Date: February 25, 2021
/s/ Frances Aldrich Sevilla-Sacasa Frances Aldrich Sevilla-Sacasa (director)	Date: February 25, 2021
/s/ Matthew R. Bob Matthew R. Bob (director)	Date: February 25, 2021
/s/ Barbara J. Faulkenberry Barbara J. Faulkenberry (director)	Date: February 25, 2021
/s/ Michael L. Finch Michael L. Finch (director)	Date: February 25, 2021
/s/ S.P. Johnson IV S.P. Johnson IV (director)	Date: February 25, 2021
/s/ Larry D. McVay Larry D. McVay (director)	Date: February 25, 2021
/s/ Anthony J. Nocchiero Anthony J. Nocchiero (director)	Date: February 25, 2021
/s/ James M. Trimble James M. Trimble (director)	Date: February 25, 2021
/s/ Steven A. Webster Steven A. Webster (director)	Date: February 25, 2021

REGULATION G – NON-GAAP FINANCIAL MEASURES

This 2020 Annual Report contains measures which may be deemed "non-GAAP financial measures" as defined in Item 10 of Regulation S-K of the Securities Exchange Act of 1934, as amended.

RECONCILIATION OF NET LOSS (GAAP) TO ADJUSTED EBITDA (NON-GAAP)

We calculate adjusted earnings before interest, income taxes, depreciation, depletion and amortization ("Adjusted EBITDA") as net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of evaluated oil and gas properties, non-cash stock-based compensation expense, merger and integration expense, (gain) loss on extinguishment of debt, and other operating expenses. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, the Company believes that adjusted EBITDA provides additional information with respect to our performance or ability to meet our future debt service, capital expenditures and working capital requirements. Because adjusted EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDA presented below may not be comparable to similarly titled measures of other companies.

($000s)	FY 2020
Net loss	**($2,533,621)**
Loss on derivatives contracts	27,773
Gain on commodity derivative settlements, net	95,856
Non-cash stock-based compensation expense	2,663
Impairment of evaluated oil and gas properties	2,547,241
Merger and integration expense	28,482
Other expense	14,625
Income tax expense	122,054
Interest expense, net of capitalized amounts	94,329
Depreciation, depletion and amortization	480,631
Gain on extinguishment of debt	(170,370)
Adjusted EBITDA	**$709,663**
Total Production MBOE	37,193
Adjusted EBITDA per BOE	$19.08

RECONCILIATION OF NET CASH PROVIDED BY OPERATING ACTIVITIES (GAAP) TO ADJUSTED FREE CASH FLOW (NON-GAAP)

Adjusted free cash flow is a supplemental non-GAAP measure that is defined by the Company as adjusted EBITDA less operational capital, capitalized interest, net interest expense and capitalized cash G&A (which excludes capitalized expense related to share-based awards). We believe adjusted free cash flow is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Adjusted free cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities, or as a measure of liquidity, or as an alternative to net income (loss).

($000s)	2Q 20	3Q 20	4Q 20	FY 2020
Net cash provided by operating activities	**$97,801**	**$135,701**	**$134,578**	**$559,775**
Changes in working capital and other	40,078	14,473	12,011	33,993
Change in accrued hedge settlements	(14,480)	(5,993)	(5,055)	(3,015)
Cash interest expense, net	21,944	24,246	24,167	90,428
Merger and integration expense	8,067	2,465	2,120	28,482
Adjusted EBITDA	**$153,410**	**$170,892**	**$167,821**	**$709,663**
Less: Operational capex	85,087	38,408	$87,488	488,623
Less: Capitalized interest	20,924	20,675	23,015	88,599
Less: Interest expense, net of capitalized amounts	22,682	24,683	26,486	94,329
Less: Capitalized cash G&A	6,740	6,831	6,465	27,407
Adjusted Free Cash Flow	**$17,977**	**$80,295**	**$24,367**	**$10,705**

Corporate Data

STOCKHOLDER INFORMATION

Callon Website
The Company website can be found at www.callon.com. It contains news releases, corporate governance materials, the annual report, recent investor presentations, stock quotes, and a link to SEC filings.

Common Stock Dividend Policy
It is anticipated that all available funds will be reinvested in the Company's business activities. Therefore, the Company has no current plans to pay dividends on its common stock.

Market for Common Stock
Effective April 22, 1998, the Company's Common Stock began trading on the New York Stock Exchange under the symbol "CPE."

CEO Section 303A.12(A) Certification
In accordance with requirements mandated by the New York Stock Exchange under Section 303A.12(a) of the Listed Company Manual, each public company is required to disclose in its Annual Report to Shareholders that its CEO certification was filed and to state any qualifications to such certification. On behalf of Joseph C. Gatto, Jr., the company filed the required certification on February 25, 2021 without qualification.

Transfer Agent and Registrar
AST Financial
6201 15th Avenue
Brooklyn, New York 11219
(718) 921-8200

Independent Registered Public Accounting Firm
Grant Thornton LLP
Houston, Texas

Administrative Agent Bank
JPMorgan Chase Bank, N.A.
New York, New York

Headquarters
Callon Headquarters Building
2000 W. Sam Houston Parkway South
Suite 2000
Houston, TX 77042

Mailing Address
Callon Petroleum Company
2000 W. Sam Houston Parkway South
Suite 2000
Houston, TX 77042

Permian Operations Office
Callon Petroleum Company
6 Desta Drive, 4th Floor
Midland, TX 79705

Eagle Ford Operations Office
Callon Petroleum Company
262 County Line Road
Dilley, TX 78017

Form 10-K
The Company's Annual Report on Form 10-K, as audited by Grant Thornton, excluding exhibits, has been incorporated into this Annual Report.

OFFICERS OF THE COMPANY

Joseph C. Gatto, Jr.
President and Chief Executive Officer

James P. Ulm, II
Senior Vice President and Chief Financial Officer

Dr. Jeffrey S. Balmer
Senior Vice President and
Chief Operating Officer

Michol L. Ecklund
Senior Vice President, General Counsel
and Corporate Secretary

Liam D. Kelly
Vice President of Corporate Development

Jamin B. McNeil
Vice President – Production

J. Michael Hastings
Vice President – Marketing

Gregory F. Conaway
Vice President and Chief Accounting Officer

Rex A. Bigler
Vice President – Asset Development

BOARD OF DIRECTORS

Richard L. Flury, Chairman of the Board
Former Chief Executive,
Gas, Power and Renewables
British Petroleum plc (retired)
Director, McDermott International

Frances Aldrich Sevilla-Sacasa
Former Chief Executive Officer,
Banco Itau International
Former Director, Carrizo Oil & Gas, Inc.
Director, Camden Property Trust

Matthew R. Bob
President, Eagle Oil & Gas Company
Director, Southcross Energy

Major General (Ret.) Barbara Faulkenberry
Former Major General,
Vice Commander U.S. Air Force
Director, USA Truck

Michael L. Finch
Former Chief Financial Officer
and Director, Stone Energy
Member of Advisory Board, C.H.
Fenstermaker & Associates
Former Director, Petroquest Energy

S.P. "Chip" Johnson, IV
Former Chief Executive Officer,
Carrizo Oil & Gas
Director, Southwestern Energy

Larry D. McVay
Former Chief Operating Officer,
TNK-BP Holdings British Petroleum plc
Joint Venture (retired)
Director, Linde plc

Anthony J. Nocchiero
Former Sr. Vice President
and Chief Financial Officer,
CF Industries, Inc. (retired)

James M. Trimble
Former Interim Chief Executive Officer
and President, and Director,
Stone Energy Corporation
Director, Talos Energy, LLC

Steven A. Webster
Managing Partner, AEC Partners,
formerly Avista Capital
Former Director and Chairman,
Carrizo Oil & Gas, Inc.
Director, Camden Property Trust
Director, Oceaneering International, Inc.

Joseph C. Gatto, Jr.
President and Chief Executive Officer

2020 Annual Report
This Annual Report and the statements contained in it are submitted for the general information of the shareholders of Callon Petroleum Company. The information is not presented in connection with the sale or the solicitation of any offer to buy any securities, nor is it intended to be a representation by the Company of the value of its securities. If you have questions regarding this Annual Report or the Company, or would like additional copies of this report, please contact our Investor Relations Department at 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042. Phone: (281) 589-5200, Email: ir@callon.com

Investors, Security Analysts And Media Relations
Shareholders, brokers, securities analysts, portfolio managers, or financial news media seeking information about the company may email us at ir@callon.com or call Mark Brewer, Investor Relations @ 281-589-5200. Written inquiries may be sent to 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

CALLON.COM
NYSE: CPE