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, 2022
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)

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

Title of Each Class	Trading Symbol	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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2022 was approximately $ 2.4 billion.

The registrant had 61,625,170 shares of common stock outstanding as of February 17, 2023.

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, 2022) relating to the 2023 Annual Meeting of Shareholders 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, as amended (the "Securities Act"), 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 "2022 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 Part I, Item 1A of this 2022 Annual Report on Form 10-K.

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 as 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:

- **12-Month Average Realized Price**: Average realized prices for sales of oil, NGLs, and natural gas on the first calendar day of each month during a trailing 12-month period.
- **ASU**: Accounting standards update.
- **Bbl** or **Bbls**: Barrel or barrels of oil or NGLs.
- **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.
- **Boe/d**: Boe per day.
- **Btu**: 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 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.

- **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.
- **ESG:** Environmental, social and governance.
- **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**: Accounting principles generally accepted in the United States.
- **GHG**: Greenhouse gases.
- **Henry Hub**: 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.
- **HSC:** Houston Ship Channel, a delivery point in Houston, Texas that serves as a benchmark price for natural gas.
- **LIBOR**: London Interbank Offered Rate.
- **LOE**: Lease operating expense.
- **MBbls**: Thousand barrels of oil.
- **MBoe**: Thousand Boe.
- **Mcf**: Thousand cubic feet of natural gas.
- **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.
- **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 ("PDPs"):** 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. 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 ("PUDs"):** 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.
- **PV-10 (Non-GAAP):** 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. 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.
- **SEC**: United States Securities and Exchange Commission.
- **SOFR:** Secured Overnight Financing Rate
- **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 in South Texas. 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, cash flow-generating business in the Eagle Ford.

Major Developments in 2022

Financing and Liquidity Highlights

- Decreased our total outstanding long-term debt principal balance by approximately 17% to $2.3 billion as of December 31, 2022, from $2.7 billion as of December 31, 2021.
- On June 24, 2022, we issued $600.0 million in aggregate principal amount of 7.5% senior unsecured notes due 2030 (the "7.5% Senior Notes") for proceeds of approximately $588.0 million, net of initial purchasers' discounts and commissions. Also on June 24, 2022, we used the proceeds from the offering of the 7.5% Senior Notes, along with borrowings under our credit facility, to redeem all of our outstanding 6.125% Senior Notes due 2024 (the "6.125% Senior Notes") and 9.0% Second Lien Senior Secured Notes due 2025 (the "Second Lien Notes").
- On October 19, 2022, we entered into the Amended & Restated Credit Agreement (the "Credit Agreement" and the senior secured revolving credit facility thereunder, the "Credit Facility") on substantially similar terms as those in the credit agreement governing our prior credit facility. The Credit Agreement, among other things, extended maturity until October 19, 2027, established a borrowing base of $2.0 billion, with an elected commitment amount of $1.5 billion, replaced all provisions and related definitions regarding LIBOR with a SOFR based benchmark rate, and decreased the maximum leverage ratio from 4.00 to 1.00 to 3.50 to 1.00.
- Reduced the borrowings outstanding under our Credit Facility from $785.0 million as of December 31, 2021 to $503.0 million as of December 31, 2022.

See "Note 7 – Borrowings" of the Notes to our Consolidated Financial Statements for further discussion.

Operational Activity. The following tables present our net daily production, as well as our operated drilling and completion activity for the year ended December 31, 2022 along with our drilled but uncompleted and producing wells as of December 31, 2022.

	Permian	Eagle Ford	Total
Production volumes			
Crude oil (Bbls/d)	49,427	15,338	64,765
Natural gas (Mcf/d)	97,313	16,733	114,046
NGLs (Bbls/d)	17,600	2,881	20,481
Total production volumes (Boe/d)	**83,246**	**21,008**	**104,254**
Percent of total production	**80 %**	**20 %**	**100 %**

	Permian		Eagle Ford		Total	
Operated Well Data	Gross	Net	Gross	Net	Gross	Net
Drilled	94	85.4	20	17.6	114	103.0
Completed	80	71.1	26	23.4	106	94.5
As of December 31, 2022						
Drilled but uncompleted	34	32.0	—	—	34	32.0
Producing	755	663.7	604	544.3	1,359	1,208.0

Our Business Strategy

Our strategy is to create value for our shareholders through the safe and capital-efficient development of our oil and gas properties, which we call our "Life of Field" co-development model. Our people work to safely reduce our operating costs, maximize our cash flows and empower the communities in which our people live and work. The key elements of our strategy include:

- We employ a "Life of Field" co-development model that enhances the value of our asset base and helps ensure capital efficiency, free cash flow generation, and ultimately long-term value creation. Utilizing our extensive database of subsurface information, we have demonstrated an ability to enhance returns today, while mitigating risks associated with future infill developments;
- We strive to create new capital efficiencies across the enterprise. Human, technology, and capital resources are carefully applied to our highest long-term return opportunities and our teams are incentivized to create value by safely lowering costs, improving well productivity and improving our returns on capital;
- We integrate sustainable business practices that aim to minimize our impact on the environment, empower and develop a diverse workforce, and enrich our communities; and
- We enhance our financial position, focus on appropriate capital allocation decisions under various commodity pricing scenarios, effectively manage risks to ensure cash flows to fund our development programs and maintain and improve our balance sheet.

Our Strengths

The following attributes position us to achieve our objectives:

- **Oily Asset Portfolio** – We have a deep inventory of high-quality drilling locations in the Permian and Eagle Ford with a high percentage of oil and liquids hydrocarbons. The plays are located in Texas, which has a regulatory environment that encourages the timely development of the state's natural resources. In addition, our developments are located in proximity to infrastructure and price-advantaged markets along the Texas Gulf Coast;
- **Proven Operator with a History of Maximizing Value** – We are stewards of the resource and believe our "Life of Field" co-development model has been a differentiator in the industry. We believe it optimizes the long-term value of our inventory, mitigates future degradation risks associated with infill drilling and generates capital efficiencies. We consistently deploy our capital to large-scale projects and carefully select the dedicated service providers required to execute our programs effectively. In addition, we have proven our ability to identify, acquire, and integrate acquisitions in our areas of focus while creating incremental value through realizing synergies;
- **Returns-Driven Strategy to Generate Free Cash Flow** – We have a demonstrated track record of capital discipline, investing less than our annual cash flow with capital spending governed by defined economic thresholds focused on capital efficiencies to enhance long-term returns. We proactively hedge a portion of our production to manage the variability in cash flows and have also secured capacity on oil and natural gas pipelines to improve our ability to market our production; and
- **ESG Focus** – We have proven our ability to create value responsibly. Our compensation programs incentivize the right behaviors to ensure a safe workplace while minimizing the impact of our operations on the environment.
    - *Environment.* We are committed to environmental stewardship and have established goals to achieve meaningful reductions for both carbon and methane emissions.
    - *Social.* We foster an entrepreneurial workplace where individuals are encouraged and empowered to share their ideas and perspectives and to develop and implement plans to bring those ideas to fruition. We embrace a culture of diversity and inclusion, where individuals feel respected, heard, and empowered.
    - *Governance.* We are committed to effective and sustainable corporate governance, which we believe promotes the long-term interests of stakeholders. We have a board with a high level of diversity, including in skills and perspectives, that allows them to perform their strategic and oversight roles satisfactorily for our stakeholders. In addition, our compensation programs incorporate metrics that align with our ESG goals.

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, 2022, 2021, and 2020. The estimated proved reserves in the table below were prepared by DeGolyer and MacNaughton ("D&M"), Callon's independent third-party reserve engineers. For further information concerning D&M's estimates of our proved reserves as of December 31, 2022, see the reserve report included as an exhibit to this 2022 Annual Report on Form 10-K. In accordance with SEC rules, we used the 12-Month Average Realized Price of oil, NGLs, and natural gas in the calculation of our estimated proved reserves and PV-10.

	As of December 31,		
	2022	**2021**	**2020**
Proved developed reserves			
Crude oil (MBbls)	170,866	162,886	128,923
Natural gas (MMcf)	351,278	332,266	238,119
NGLs (MBbls)	63,788	55,720	43,315
Total proved developed reserves (MBoe)	**293,200**	**273,983**	**211,925**
Proved undeveloped reserves			
Crude oil (MBbls)	104,743	127,410	160,564
Natural gas (MMcf)	241,565	245,061	303,479
NGLs (MBbls)	41,321	42,384	52,811
Total proved undeveloped reserves (MBoe)	**186,325**	**210,638**	**263,954**
Total proved reserves			
Crude oil (MBbls)	275,609	290,296	289,487
Natural gas (MMcf)	592,843	577,327	541,598
NGLs (MBbls)	105,109	98,104	96,126
Total proved reserves (MBoe)	**479,525**	**484,621**	**475,879**
Proved developed reserves %	61 %	57 %	45 %
Proved undeveloped reserves %	39 %	43 %	55 %
12-Month Average Realized Prices			
Crude oil ($/Bbl)	$95.02	$65.44	$37.44
Natural gas ($/Mcf)	$5.75	$3.31	$1.02
NGLs ($/Bbl)	$36.40	$29.19	$11.10
Standardized measure of discounted future net cash flows (GAAP) (in millions)	**$9,004.1**	**$6,250.8**	**$2,310.4**
PV-10 (Non-GAAP) (in millions):			
Proved developed PV-10	$7,122.9	$4,502.6	$1,577.3
Proved undeveloped PV-10	3,411.9	2,548.7	767.7
Total PV-10 (Non-GAAP)	**$10,534.8**	**$7,051.3**	**$2,345.0**

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. 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,		
	2022	**2021**	**2020**
		(In millions)	
Standardized measure of discounted future net cash flows (GAAP)	**$9,004.1**	**$6,250.8**	**$2,310.4**
Add: present value of future income taxes discounted at 10% per annum	1,530.7	800.5	34.6
PV-10 (Non-GAAP)	**$10,534.8**	**$7,051.3**	**$2,345.0**

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.

The following table presents our estimated proved reserves of December 31, 2022.

	Permian	Eagle Ford	Total
Proved reserves			
Crude oil (MBbls)	227,293	48,316	275,609
Natural gas (MMcf)	537,780	55,063	592,843
NGLs (MBbls)	95,362	9,747	105,109
Total proved reserves (MBoe)	**412,285**	**67,240**	**479,525**
Percent of proved developed reserves	**82 %**	**18 %**	**100 %**
Percent of proved undeveloped reserves	**92 %**	**8 %**	**100 %**

The following table provides a summary of the changes in our proved reserves for the year ended December 31, 2022.

	Total (MBoe)
Proved reserves as of December 31, 2021	**484,621**
Extensions and discoveries	67,961
Revisions to previous estimates	(31,645)
Sales of reserves in place	(3,359)
Production	(38,053)
Proved reserves as of December 31, 2022	**479,525**

Further details of the changes in our proved reserves for the year ended December 31, 2022 are as follows:

- *Extensions and Discoveries.* We added 68.0 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 2022:

Extensions and discoveries	Total (MBoe)
Total proved	67,961
Proved undeveloped	59,231
Difference (Proved developed producing) (1)	**8,730**

(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 $115.5 million for the extensions and discoveries associated with proved developed producing wells and $44.7 million on facilities associated with existing proved developed producing wells during 2022.

- *Revisions to Previous Estimates.* Net negative revisions of previous estimates of 31.6 MMBoe primarily consist of:
  - 44.4 MMBoe reduction due to PUD locations that were reclassified to unproved reserve categories, all of which were in the Permian. Certain PUDs were moved outside of their five-year development window as we continue to refine our future development plans for the Permian, including increased application of our "Life of Field" co-development model. This development model focuses on optimization of the value of a reservoir system through concurrent, co-development of multiple target zones within the system utilizing larger scale projects. As a result, we believe the model contributes to more consistent capital efficiency of our well inventory over time and our broader Permian development program is now being targeted for larger project sizes, accompanied by longer associated cycle times, based on our testing and delineation efforts during 2022;
  - 13.1 MMBoe reduction primarily due to higher operating costs; offset by
  - 13.7 MMBoe increase primarily due to the change in 12-Month Average Realized Price of crude oil which increased by approximately 45% as compared to December 31, 2021; and
  - 12.2 MMBoe increase primarily due to better results than previously forecasted on certain wells turned to production during 2022 in both the Permian and Eagle Ford.
- *Sales of Reserves in Place.* The 3.4 MMBoe of sales of reserves in place were primarily associated with the divestitures of non-core assets primarily in the Western Delaware Basin.

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 2023 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, 2022.

	Total (MBoe)
PUDs as of December 31, 2021	**210,638**
Extensions and discoveries	59,231
Revisions to previous estimates	(39,843)
Converted to proved developed	(43,701)
PUDs as of December 31, 2022	**186,325**

- *Extensions and Discoveries.* We added 59.2 MMBoe of new reserves in extensions and discoveries, all in the Permian, as a result of additional offset locations associated with our drilling program.
- *Revisions to Previous Estimates.* Net negative revisions of previous estimates of 39.8 MMBoe primarily consist of:
  - 44.4 MMBoe reduction due to PUDs that were removed primarily as a result of changes in our development plans as described above;
  - 2.9 MMBoe reduction primarily due to higher operating costs; offset by
  - 2.6 MMBoe increase primarily due to the change in 12-Month Average Realized Price of crude oil which increased by approximately 45% as compared to December 31, 2021; and
  - 4.9 MMBoe increase primarily due to increased anticipated hydrocarbon recoveries resulting from observed well performance over longer production timeframes during the testing of various full field development plan concepts.
- *Converted to Proved Developed.* During 2022, we converted 43.7 MMBoe of PUDs that were booked as PUDs as of December 31, 2021 to proved developed at a cost of $445.9 million, or $10.20 per Boe.

During 2022, we also incurred $153.9 million on PUDs that were drilled but uncompleted as of December 31, 2022. As of December 31, 2022, we had 23.2 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 2023, and we expect to incur approximately $122.3 million of capital expenditures to complete these wells. We also incurred $65.9 million on wells in progress in 2022.

At December 31, 2022, 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, 2022, 2021, and 2020. 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. D&M does not own an interest in our properties and is not 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 Operations 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 Operations 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 Operations 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 Operations 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 "Note 18 – Supplemental Information on Oil and Natural Gas Operations" of the Notes to our Consolidated Financial Statements 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 a capital budget for $1.0 billion (the "2023 Capital Budget"), with approximately 80% directed towards drilling, completion, and equipment expenditures. Our scaled development plan for 2023 will continue to employ our "Life of Field" co-development model, whereby capital is allocated towards full field development plans of depletion and optimal usage of infrastructure. Over 80% of the 2023 Capital Budget is allocated to development in the Permian with the balance for development in the Eagle Ford.

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, 2022, 2021, and 2020. 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,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Extension Wells - Productive	20	17.7	19	17.2	22	16.0
Extension Wells - Non-productive	—	—	—	—	—	—
Development Wells - Productive	86	76.8	93	86.7	73	66.0
Development Wells - Non-productive	—	—	—	—	—	—

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, 2022.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Permian - Operated	956	841.0	99	84.1	1,055	925.1
Permian - Non-operated	47	5.8	1	0.1	48	5.9
Total Permian	1,003	846.8	100	84.2	1,103	931.0
Eagle Ford - Operated	543	489.8	87	76.0	630	565.8
Eagle Ford - Non-operated	17	0.2	—	—	17	0.2
Total Eagle Ford	560	490.0	87	76.0	647	566.0
Total	**1,563**	**1,336.8**	**187**	**160.2**	**1,750**	**1,497.0**

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, natural gas and NGLs for the periods indicated. For further details, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations".

	Years Ended December 31,		
	2022	**2021**	**2020**
Total production			
Oil (MBbls)			
Permian	18,041	14,475	14,113
Eagle Ford	5,598	7,749	9,430
Total oil	**23,639**	**22,224**	**23,543**
Natural gas (MMcf)			
Permian	35,519	29,682	32,087
Eagle Ford	6,108	7,704	8,714
Total natural gas	**41,627**	**37,386**	**40,801**
NGLs (MBbls)			
Permian	6,424	5,155	5,390
Eagle Ford	1,052	1,284	1,460
Total NGLs	**7,476**	**6,439**	**6,850**
Total production (MBoe)			
Permian	30,385	24,577	24,851
Eagle Ford	7,668	10,317	12,342
Total barrels of oil equivalent	**38,053**	**34,894**	**37,193**
Average realized sales price (excluding impact of derivative settlements)			
Oil (per Bbl)	$95.72	$68.22	$36.13
Natural gas (per Mcf)	5.59	3.78	1.27
NGL (per Bbl)	34.84	30.11	11.87
Total average realized sales price (per Boe)	**$72.42**	**$53.06**	**$26.45**
Operating costs per Boe			
Lease operating expense	$7.63	$5.82	$5.22
Production and ad valorem taxes	$4.20	$2.87	$1.68
Gathering, transportation and processing	$2.55	$2.32	$2.08

Major Customers

We market the majority of the production from properties we operate on account of both ourselves and that of the other working interest owners in these properties. We generally sell our production to purchasers at prevailing market prices, which in certain cases are adjusted for contractual differentials, under contracts ranging from terms of one month to multiple years. The following table presents customers that represented 10% or more of our oil, natural gas and NGL revenues for at least one of the periods presented:

	Years Ended December 31,		
	2022 (1)	**2021** (1)	**2020** (1)
Valero Marketing and Supply Company	15%	13%	23%
Rio Energy International, Inc.	12	*	*
Shell Trading Company	*	20	31
Trafigura Trading, LLC	*	15	*
Occidental Energy Marketing, Inc.	*	13	*

(1) The customers that represented over 10% of our sales of purchased oil and gas were Vitol Inc., for the years ended December 31, 2022, 2021 and 2020, and Plains Marketing, L.P., for the year ended December 31, 2022.

* - 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 our customers to provide financial security.

Leasehold Acreage

The following table shows our approximate developed and undeveloped leasehold acreage as of December 31, 2022. 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	2023	2024	2025
Permian [1]	146,238	124,078	5,459	3,015	151,697	127,093	525	964	430
Eagle Ford	61,526	51,624	2,719	275	64,245	51,899	32	—	21
Other [2]	2,019	62	15,845	7,393	17,864	7,455	3,398	2,994	—
Total	**209,783**	**175,764**	**24,023**	**10,683**	**233,806**	**186,447**	**3,955**	**3,958**	**451**

(1) Based on our current plans, approximately 99%, 61% and 58% of the acreage expiring in the Permian in 2023, 2024 and 2025, respectively, will be developed prior to expiration or extended by lease extension payments.

(2) Consists of non-core acreage principally located in Presidio County, Texas. We have no current development plans and no proved undeveloped reserves associated with this acreage as of December 31, 2022.

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 2023, 2024 and 2025 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, accounting 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 support personal growth and prepare employees for high impact roles and leadership positions.

As of December 31, 2022, Callon had 354 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, 2022, approximately 41% of our permanent, full-time employees identified as a racial or ethnic minority, 22% were female, and 32% of non-field employees were female. We seek to expand diversity in our workforce, and in 2022, 50% of our newly hired employees identified as a racial or ethnic minority and 36% were female.
- **Health and Safety** – Protecting our employees, contractors and communities is a core value at Callon and a top priority. Our Operations Management System (“OMS”) establishes clear expectations for operating safely and responsibly throughout the lifecycle of our business. We seek to 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; the policy includes each individual’s authorization and responsibility to stop work on any activity

for safety reasons 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 2022 annual bonus program.

- **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, operational, 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. We also offer comprehensive benefit options including a retirement savings plan, life and disability insurance, health savings accounts, flexible spending accounts, and a charitable matching program.
- **Employee Development** – We believe that ongoing investment in the development of our team members is key to our future success, as well as the retention of our employees. 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 tuition assistance and access to various training programs, including a monthly in-house leadership development program. Our leaders seek to support all of our employees in reaching their personal goals through ongoing feedback and development conversations.

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 2022 Annual Report on Form 10-K.

Other

Industry Segment and Geographic Information

For segment reporting purposes, Callon 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 our assets are located within the United States and all operations are located within Texas.

Title to Properties

We believe that the title to our 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. Our properties are potentially subject to burdens such as royalty, overriding royalty, working and other outstanding interests customary in the industry. To the extent that such burdens and obligations affect our rights to production revenues, these characteristics have been taken into account in calculating our net revenue interests and in estimating the size and value of our estimated proved reserves. We believe 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

We operate in the oil and natural gas industry, which is highly competitive. Our business experiences strong competition from a number of parties that may range from small independent producers to major integrated companies. Competition affects our 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 our competitors 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, we maintain insurance against some of the operating risks to which our business is exposed. While not all inclusive, our 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 our exploration and production operations.

We enter into master service agreements with our third-party contractors, including hydraulic fracturing contractors, in which they agree to indemnify us for injuries and deaths of the service provider’s employees, as well as contractors and subcontractors hired by the service provider. Similarly, we generally agree to indemnify each third-party contractor against claims made by our employees and our other contractors. Additionally, each party generally is responsible for damage to its own property. We reevaluate 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 we believe that we are properly insured based on our risk analysis, no assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable. In such circumstances, we may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Corporate Offices

Our headquarters are located in Houston, Texas, in buildings with office space that we lease. 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 at the federal, state, and local levels. Some of these requirements carry substantial penalties for failure to comply. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision, and various proposals and proceedings that might affect the industry are pending before Congress, federal administrative agencies such as the Federal Energy Regulatory Commission ("FERC"), various state and administrative agencies and legislatures, and the courts. We cannot predict what effect such proposals or proceedings may have on our operations, capital expenditures, earnings or competitive position.

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.

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, operations, 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 the protection of the environment and natural resources. 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, monitor for 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." 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 strict, 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 of 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 "Corps"). The EPA and the Corps issued a final rule on the federal jurisdictional reach over waters of the United States in 2015 that never took effect before being replaced by the Navigable Waters Protection Rule (the "NWPR") in December 2019. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, and it was vacated by a federal district court in August 2021. The EPA is undergoing a two-phase rulemaking process to redefine the definition of waters of the United States and that process could be impacted by the U.S. Supreme Court's upcoming decision in Sackett v. EPA, a case regarding the proper test in determining whether wetlands qualify as navigable waters of the United States. A final rule, known as "Rule 1," was announced by the EPA and the Corps in December 2022. The EPA and the Corps are expected to propose a second rule, known as "Rule 2," further refining Rule 1 by November 2023 and issue a final rule by July 2024.

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 (the "CAA"), 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 CAA 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.

In June 2016, the EPA finalized regulations establishing New Source Performance Standards, known as Subpart OOOOa, for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized two sets of amendments to the 2016 Subpart OOOOa standards. The first, known as the 2020 Technical Rule, reduced the 2016 rule's fugitive emissions monitoring requirements and expanded exceptions to pneumatic pump requirements, among other changes. The second, known as the 2020 Policy Rule, rescinded the methane-specific requirements for certain oil and natural gas sources in the production and processing segments. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the 2020 Technical Rule by September 2021 and consider revising the 2020 Policy Rule. On June 30, 2021, President Biden signed a Congressional Review Act (the "CRA") resolution passed by Congress that revoked the 2020 Policy Rule. The CRA did not address the 2020 Technical Rule.

Further, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. Under the proposed rule, states would have three years to develop their compliance plan for existing sources and the regulations for new sources would take effect immediately upon issuance of a final rule. On November 11, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." The EPA is expected to issue a final rule by August 2023.

As a result of these regulatory changes, the scope of any final methane regulations or the costs for complying with federal methane regulations are uncertain. However, any new regulations could result in stricter permitting requirements, which in turn could delay or impair our ability to obtain air emission permits and could result in increased expenditures for pollution control equipment, the costs of which could be significant.

Climate Change. Numerous reports from scientific and governmental bodies such as the Sixth Assessment Report of the 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.

At the international level, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change ("UNFCCC") resulted in nearly 200 countries, including the United States, coming together to develop the Paris Agreement, intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. In 2020, the U.S. withdrew from the Paris Agreement. However, in February 2021, the current administration rejoined the Paris Agreement and later announced a target for the U.S. to achieve a 50% to 52% reduction from 2005 levels in economy-wide GHG emissions by 2030. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030, including "all feasible reductions" in the energy sector. Since its formal launch at the 26th Conference of the Parties of the UNFCCC ("COP26"), over 150 countries have joined the pledge. Most recently, at the 27th conference of parties ("COP27"), President Biden announced the EPA's proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. International commitments, re-entry into the Paris Agreement and President Biden's executive orders may result in the development of additional regulations or changes to existing regulations.

While the Biden Administration has pursued executive actions to address climate change, and while Congress has from time to time considered legislation to reduce emissions of GHGs, no new comprehensive federal laws regulating the emission of GHGs or directly imposing a price on carbon have been adopted in recent years. However, such legislation has periodically been introduced in the U.S. Congress and may be proposed or adopted in the future. In addition, many state and local leaders have intensified or stated their intent to intensify efforts to support international climate commitments and treaties, in addition to developing programs that are aimed at reducing GHG emissions by means of cap and trade programs, carbon taxes, or encouraging the use of renewable energy or alternative low-carbon fuels.

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. At the federal level, the $1 trillion legislative infrastructure package passed by Congress in November 2021 includes a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events, and clean energy and transportation investments. The Inflation Reduction Act of 2022 ("IRA 2022") also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change.

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.

Additionally, on March 21, 2022, the SEC issued a proposed rule regarding the enhancement and standardization of mandatory climate-related disclosures for investors. The proposed rule would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about the registrant's governance of climate-related risks and relevant risk management processes; climate-related risks that are reasonably likely to have a material impact on the registrant's business, results of operations, or financial condition and their actual and likely climate-related impacts on the registrant's business strategy, model, and outlook; climate-related targets, goals and transition plan (if any); certain climate-related financial statement metrics in a note to their audited financial statements; Scope 1 and Scope 2 GHG emissions; and Scope 3 GHG emissions and intensity, if material, or if the registrant has set a GHG emissions reduction target, goal or plan that includes Scope 3 GHG emissions. Although the proposed rule's ultimate date of effectiveness and the final form and substance of these requirements is not yet known and the ultimate scope and impact on our business is uncertain, compliance with the proposed rule, if finalized, may result in increased legal, accounting and financial compliance costs, make some activities more difficult, time-consuming and costly, and place strain on our personnel, systems and resources.

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. The EPA evaluated the potential impacts of hydraulic fracturing on drinking water resources and concluded 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. Further, the EPA prohibits the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

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. For example, the RRC has created several "seismic response areas" in west Texas and limited certain deep oil and gas wastewater disposal activities in portions of west Texas due to seismicity concerns. The U.S. Geological Survey has 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 federal actions having the potential to significantly impact the human 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. The new regulations were subject to litigation in several federal district courts and were stayed pending an ongoing review of the 2020 rule. On October 6, 2021, the Council on Environmental Quality announced its Phase 1 rule, the first of two planned rules to roll back the 2020 rule, which was finalized on April 20, 2022. The Phase 1 final rule generally restores certain regulatory provisions that were in effect prior to the 2020 rule. 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 ("NMFS") 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 these rules. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations, which were also subject to litigation. In June and July 2022, the FWS issued final rules rescinding the regulations defining "habitat" and governing critical habitat exclusions. 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 revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental take under certain prescribed conditions. The notice of proposed rulemaking is expected in March 2023 and is expected to be finalized by the end of 2023. 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. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

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, conditions 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, natural gas, condensate, and NGL 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 NGLs 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. 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 may 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 NGLs 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 that have resulted in the complete removal of all price and non-price controls for "first sales" of natural gas, which include all of our sales of our own production.

Under the Energy Policy Act of 2005 ("EPAct 2005") 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. FERC also has authority to order the disgorgement of any ill-gotten gains. EPAct 2005 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 or purchases 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. Such regulations affect 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. 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, not 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, and provisions under such tariffs 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 and disgorgement of any ill-gotten gains.

With respect to its regulation of natural gas pipelines under the NGA, FERC traditionally has not required the applicant for construction and operation 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 D.C. 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. In March 2021, FERC assessed the significance of a project's GHG emissions and those emissions' contribution to climate change. FERC compared the project's reasonably foreseeable GHG emissions to the total GHG emissions of the United States to assess the project's share of contribution to national GHG levels. FERC announced that it will also consider state GHG emission reduction targets, to the extent a state has such targets. Finally, FERC noted that it will consider "all appropriate evidence" in future proceedings. In February 2022, as redesignated in March 2022, FERC issued a draft interim policy statement on the consideration of GHG emissions in natural gas certification proceedings, which would consider reasonably foreseeable emissions. The draft interim policy statement proposed a significant shift and expansion in FERC's review of GHG emissions in pipeline certificate proceedings. FERC has not issued a final order on the draft interim policy statement. 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 transportation 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, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019. 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. On November 15, 2021, PHMSA issued a final rule that expands PHMSA's safety regulations to more than 400,000 miles of onshore gas gathering pipelines that were previously exempt from PHMSA's rules. While PHMSA has issued final rules for some of the regulations stemming from the PIPES Act of 2020, others are still proceeding through the rulemaking process.

Oil, Condensate and NGLs Sales and Transportation. Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. The Federal Trade Commission does have anti-market manipulation authority with respect to wholesale sales of oil under the Energy Independence and Security Act of 2007 and its petroleum market manipulation rule.

The Company's sales of oil and NGLs are affected by the availability, terms, conditions and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and NGLs 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 NGL 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 NGL 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. If the regulations relating to the price, terms and conditions for access to pipeline transportation change, we could face higher transportation costs for our production and, possibly, reduced access to transportation 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 FERC, which could impact our ability to obtain new interstate pipeline transportation capacity. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil and NGL 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 not unduly 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, and such order 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. In December 2022, FERC issued an order denying rehearing and clarifying the scope of its holding in the November 2017 declaratory order and how it will assess whether future marketing affiliate transactions violate the ICA. Concurrently with the December 2022 order, FERC issued a proposed policy statement to revise its policy for evaluating whether contractual committed transportation service between oil pipelines and their affiliates complies with the ICA. At this time, the Company cannot currently determine the impact this FERC order and proposed policy statement 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, NGLs 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. In November 2021, PHMSA issued a notice of proposed rulemaking, seeking to suspend this final rule.

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 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 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

Our activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe 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 our capital expenditures, earnings or our competitive position with respect to our existing assets and operations. We 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 our 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 Reports 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 — Governance" section of our website our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation, Nominating and ESG, and Operations and Reserves 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

Our operations and financial results are subject to various risks and uncertainties, including but not limited to those described below. Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks actually occur, it could materially harm our business, financial condition or results of operations or impair our ability to implement business plans or complete development activities as scheduled. In that case, the market price of our common stock could decline. The following risk factors are summarized as risks related to the oil and natural gas industry, operational risks, marketing and transportation, reserves and drilling locations, technology, indebtedness and financial position, acquisitions, our hedging program, legal and regulatory, tax, other material risks and general risks.

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.
- 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.
- Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and potential reduction in demand for oil and natural gas.
- Negative public perception of the oil and gas industry could have a material and adverse effect on us.
- Increased scrutiny of ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.
- 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.
- An excess supply of oil and natural gas in the market 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.

Operational Risks

- Our operations are dependent on third-party service providers.
- 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.
- We are subject to physical risks arising from climate change, which may have a negative impact on our business and results of operations.
- Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.
- Multi-well pad drilling may result in volatility in our operating results.
- 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.

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.
- 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.

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.
- Unless we replace our oil and gas reserves, our reserves and production will decline.
- 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.
- The development of our PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate.

Risks Related to Technology

- We may not be able to keep pace with technological developments in our industry.

- 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.

Risks Related to Our Indebtedness and Financial Position

- Our business requires significant capital expenditures.
- Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.
- Restrictive covenants in the agreements governing our indebtedness may limit our ability to respond to changes in market conditions or pursue business opportunities.
- Adverse changes in our credit rating may affect our borrowing capacity and borrowing terms.
- Our borrowings under our Credit Facility expose us to interest rate risk.
- 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.
- 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.
- We cannot be certain that we will be able to maintain or improve our leverage position.

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 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.

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.
- 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 hedging transactions expose us to counterparty credit risk.

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.
- 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.
- Climate change legislation or regulations restricting emissions of GHG or requiring the reporting of GHG emissions or climate-related information could adversely impact our operating costs and demand for the oil and natural gas we produce.
- 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.

Tax Risks

- Our ability to use our existing net operating loss (“NOL”) carryforwards or other tax attributes could be limited.
- 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.
- Tax laws may change over time and such changes could adversely affect our business and financial condition.

Other Material Risks

- Competitive industry conditions may negatively affect our ability to conduct operations.
- 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.
- 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 loss of key personnel, or inability to employ a sufficient number of qualified personnel, could adversely affect our ability to operate.
- The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

- The COVID-19 pandemic, and various governmental actions taken to mitigate its impact, 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.
- 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.
- 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.
- We do not currently pay cash dividends on our common stock.

General Risk Factors

- Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.
- We may be subject to the actions of activist shareholders.
- 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.

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 three years ended December 31, 2022, NYMEX WTI prices ranged from a high of $123.64 per barrel on March 8, 2022 to a low of -$36.98 per barrel on April 20, 2020, and NYMEX Henry Hub prices ranged from a high of $23.86 per MMBtu on February 17, 2021 to a low of $1.33 per MMBtu on September 21, 2020. Prices were particularly volatile in 2020 and 2021, with five-year highs occurring in 2021 and five-year lows occurring 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. 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, trade embargoes or sanctions, 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. Additionally, 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, would require us to reevaluate and postpone or eliminate additional drilling.

Additionally, if we are required to curtail our drilling program, we may be unable to continue to hold 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 Prices, 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.

Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and potential reduction in demand for oil and natural gas. Increasing attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on combating climate change, together with changes in consumer and industrial/commercial behavior, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in the enactment of climate change-related regulations, policies and initiatives (at the government, regulator, corporate and/or investor community levels), including alternative energy requirements, new fuel consumption standards, energy conservation and emissions reductions measures and responsible energy development; technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in wind, solar and hydrogen power, as well as battery technology); increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. For further discussions regarding risk related to technological developments, see "—We may not be able to keep pace with technological developments in our industry." These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products. Such developments may also adversely impact, among other things, our stock price and access to capital markets, and the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Climate change-related developments may also impact the market prices of or our access to raw materials such as energy and water and therefore result in increased costs to our business.

More broadly, the enactment of climate change-related regulations, policies and initiatives across the market at the government, corporate, and/or investor community levels may in the future result in increases in our compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation). For further discussion regarding the risks posed to us by climate change-related regulations, policies and initiatives and by negative public perception of the oil and gas industry, see the discussions below in "—Negative public perception of the oil and gas industry could have a material and adverse effect on us," and "—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."

Negative public perception of the oil and gas industry could have a material and adverse effect on us. Opposition toward oil and natural gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change may lead to increased reputational and litigation risk and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. 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. Activism could materially and adversely impact our ability to operate our business and raise capital. The foregoing factors may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. In addition, various officials and candidates at the federal, state and local levels, have made climate-related pledges or proposed banning hydraulic fracturing altogether.

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, or claims alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customer. 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.

Negative perceptions regarding our industry and reputational risks may also in the future adversely affect our ability to successfully carry out our business strategy by adversely affecting our access to 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. Parties concerned about the potential effects of climate change have 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. More broadly, 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. Further, certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Institutional lenders who provide financing to companies in the energy sector have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Such developments, including ESG 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.

Increased scrutiny of ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation. In recent years, companies across all industries are facing increasing scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors and lenders, investment funds and other influential investors and rating agencies, related to their ESG and sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters (or meet sustainability goals and targets that we have set), as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected.

In addition, the Company’s continuing efforts to research, establish, accomplish and accurately report on the implementation of our ESG strategy, including any specific ESG objectives, may also create additional operational risks and expenses and expose us to reputational, legal and other risks. While we create and publish voluntary disclosures regarding ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Further, our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating public company. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder trust and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

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, during periods of increasing oil and natural gas prices and in periods in which the levels of exploration and production increase, our industry experiences a shortage of drilling and workover rigs, other equipment, pipes, materials and supplies, water and qualified personnel. As a result of such shortage, the costs and delivery times of rigs, equipment and supplies often increase substantially, as well as the wages and costs of drilling rig crews and other experienced personnel and oilfield services, while the quality of these services and equipment may suffer. This impact may be magnified to the extent that the Company's ability to participate in the commodity price increases is limited by its derivative risk management activities. Cost increases in and shortages of such resources may also result from a variety of other factors beyond our control, such as general inflationary pressures, transportation constraints, and increases in the cost of necessary inputs such as electricity, steel and other raw materials, including as a result of increased tariffs or geopolitical issues.

An excess supply of oil and natural gas in the market 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. An excess supply of oil and natural gas in the market may result in transportation and storage capacity constraints. 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.

Operational Risks

Our operations are dependent on third-party service providers. We contract with third-party service providers to support our operations. These contracted services are generally provided pursuant to master services agreements entered into between the third-party service providers and our operating subsidiaries. Although we have our own employees, our ability to conduct operations and generate revenues is dependent on the availability and performance of those third-party service providers and their compliance with the terms of their respective master service agreements. We cannot guarantee that we will be successful in either retaining the services of our current third-party service providers or contracting with alternative service providers in the event that our current contractors discontinue providing services to us or fail to meet their obligations under their respective master services agreements. Any failure to retain the services of our current service providers or locate alternatives will negatively affect our ability to generate revenues and continue and expand our operations.

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 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.

We are subject to physical risks arising from climate change, which may have a negative impact on our business and results of operations. Most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere and climate change may produce significant physical effects on weather conditions, 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 oil or natural gas products or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods, increases in our costs of operation, or reductions in the efficiency of our operations, impacts on our personnel, supply chain, or distribution chain, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Any of these effects could have an adverse effect on our assets and operations. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. Further, energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes. Increased energy use due to weather changes may require us to invest in additional equipment to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. The effect of fluctuations on supply and demand may become 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. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

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 landowners 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, available manpower, pipeline safety issues, or other reasons. 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. In addition, we or parties that we utilize might not be able to connect new wells that we complete to pipelines. Our failure to obtain access to processing and transportation facilities and services in a timely manner and 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 timing of 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 and gathering infrastructure;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather, including the effects of chronic and acute climate events associated with the effects of global climate change; 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 2022 Annual Report on Form 10-K 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 2022 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 2022 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, 2022 on the 12-Month Average Realized Prices 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 39% of our total estimated proved reserves as of December 31, 2022 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, including technological advances in fuel economy and energy generation devices or other technological advances that could reduce demand for oil and natural gas, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement 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, transportation 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. 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. We intend to fund our capital expenditures through a combination of cash flows from operations and, if needed, borrowings from financial institutions, the sale of debt and equity securities, and asset divestitures. 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, 2022, we had aggregate outstanding indebtedness of approximately $2.3 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 fund our operations and other business activities as well as any potential returns to shareholders;
- 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 the interest we pay on our indebtedness under our Credit Facility varies 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 and timing of availability 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 borrowings under our Credit Facility make us vulnerable to increases in interest rates as they bear interest at a rate elected by us that is based on the prime, SOFR or federal funds rate plus margins ranging from 0.75% to 2.75%, depending on the rate used and the amount of the loan outstanding in relation to the elected commitment.

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 $2.0 billion and $1.5 billion, respectively, and as of December 31, 2022, we had an aggregate principal balance of $503.0 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 recent acquisitions 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, data, 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, data, 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 look to acquire additional acreage in Texas or other regions. 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, natural gas, and NGL prices and to achieve more predictable cash flow. Our hedges at December 31, 2022 are in the form of collars, swaps, put and call options, basis swaps, and other structures placed with the commodity trading branches of certain 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, natural gas, and NGLs. 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, natural gas, and NGL prices. To the extent that oil, natural gas, and NGL 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.

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 and takes into account our view of current and future market conditions in order to provide greater certainty of cash flows to meet our debt service costs and capital program. We generally hedge for the next 12 to 24 months. 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 requirements to protect our employees and mitigate safety risks;
- 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 review, revise and supplement environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as emissions monitoring and 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 from time to time, 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, the EPA regulates hydraulic fracturing with fluids containing diesel fuel under the UIC program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. The EPA has recently taken steps to strengthen its methane standards, including most recently in November 2021 and 2022, when the EPA issued a proposed rule and supplemental rule intended to reduce methane emissions from oil and gas sources. The November 2021 rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the November 2021 rule would establish “Emissions Guidelines,” creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by EPA. States would have three years to develop their compliance plan for existing sources and the regulations for new sources would take effect immediately upon issuance of a final rule. Additionally, on November 11, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as “super emitters.” The EPA is expected to issue a final rule by August 2023. The scope of future obligations remains uncertain; 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 impose new limits on the volumes of, 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. The RRC's "well integrity rule" 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, the RRC rules require 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. Further, the RRC has 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, and limit volumes for, 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.

The EPA has also issued the "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States" report, concluding 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 or requiring the reporting of GHG emissions or climate-related information 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 proposed additional rules, and the U.S. Congress has, from time to time, considered adopting legislation to reduce or tax 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 some existing and proposed GHG rules and regulations, see "Business and Properties—Regulations."

At the international level, 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 intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. 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. In 2020, the United States withdrew from the Paris Agreement. However, in February 2021, the current administration rejoined the Paris Agreement and later announced a target for the U.S. to achieve a 50% to 52% reduction from 2005 levels in economy-wide GHG emissions by 2030. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030, including "all feasible reductions" in the energy sector. Since its formal launch at the COP26, over 150 countries have joined the pledge. Most recently, at the 27th conference of parties ("COP27"), President Biden announced the EPA's proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. In addition, 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 or that require the reporting of GHG emissions or other climate-related information 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, and to monitor and report on GHG emissions. 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. International commitments, re-entry into the Paris Agreement, and President Biden's executive orders may result in the development of additional regulations or changes to existing regulations. At the federal level, although no comprehensive climate change legislation regulating the emission of GHGs or directly imposing a price on carbon has been implemented to date, such legislation has periodically been introduced in the U.S. Congress and may be proposed or adopted in the future. The $1 trillion legislative infrastructure package passed by Congress in November 2021 includes a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events and clean energy and transportation investments. The IRA 2022 also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture and other programs directed at addressing climate change. Additionally, the SEC issued a proposed rule in March 2022 that would mandate extensive disclosure of climate-related data, risks and opportunities, including financial impacts, physical and transition risks, related governance and strategy and GHG emissions, for certain public companies. We cannot predict the costs of implementation or any potential adverse impacts resulting from the rulemaking. To the extent this rulemaking is finalized as proposed, we could incur increased costs relating to the assessment and disclosure of climate-related risks. We may also face increased litigation risks related to disclosures made pursuant to the rule if finalized as proposed. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. Consequently, legislation and regulatory programs to reduce or require reporting relating to 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, and activism, litigation and initiatives aimed at limiting climate change and reducing air pollution could impact our business activities, operations and ability to access capital. For further discussion on transition risks related to climate change legislation and regulation, see "—Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could result in increased operating expenses and capital costs, financial risks and potential reduction in demand for oil and natural gas" and "—Negative public perception of the oil and gas industry could have a material and adverse effect on us."

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. 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. 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. 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 portion of our NOL carryforward balance was generated prior to the effective date of 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 2034 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, whereby the utilization of NOLs was 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 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 recent legislation such as the IRA 2022, 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 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, severe weather, delays or interruptions of production from wells in this area caused by governmental regulation, specific taxes or other regulatory legislation, 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, or inability to employ a sufficient number of qualified 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. Also, we may experience employee turnover or labor shortages if our business requirements, compensation, benefits and/or perquisites are inconsistent with the expectations of current or prospective employees, or if workers pursue employment in fields with less volatility than in the energy industry. If we are unsuccessful in our efforts to attract and retain sufficient qualified personnel on terms acceptable to us, or do so at rates necessary to maintain our competitive position, our business could be adversely affected.

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 15% of our total revenues for the year ended December 31, 2022. 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.

The COVID-19 pandemic, and various governmental actions taken to mitigate its impact, 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, and created significant volatility and disruption of financial and commodity markets. The pandemic has also increased volatility and, from time to time, caused negative pressure in the capital markets; as a result, in the future, 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 any future declines in demand due to the COVID-19 pandemic or any future pandemic.

While we expect the COVID-19 pandemic and related economic repercussions to continue to affect our business, financial condition, results of operations, and cash flows, 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. 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.

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 do not currently pay cash dividends on our common stock. We do not currently 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, a shareholder's only current 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

Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition. Concerns over global economic conditions, energy costs, supply chain disruptions, increased demand, labor shortages associated with a fully employed U.S. labor force, geopolitical issues, inflation, the availability and cost of credit and the United States financial market and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2022, due to a substantial increase in money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to 7.0% in December 2021 to 8.2% in September 2022. As of December 31, 2022, inflation was at 6.5%. Though we incorporated inflationary factors into our 2022 business plan, inflation has outpaced those original assumptions. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures and protect the requisite access to commodities and services. Nevertheless, we expect for the foreseeable future to experience supply chain constraints and inflationary pressure on our cost structure. Principally, commodity costs for steel and chemicals required for drilling, higher transportation and fuel costs and wage increases have increased our operating costs for the year ended December 31, 2022 compared to the same period in 2021. We also may face shortages of these commodities and labor, which may prevent us from executing our development plan. These supply chain constraints and inflationary pressures will likely continue to adversely impact our operating costs and, if we are unable to manage our supply chain, it may impact our ability to procure materials and equipment in a timely and cost-effective manner, if at all, which could impact our ability to distribute available cash and result in reduced margins and production delays and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

We are taking actions to mitigate supply chain and inflationary pressures. We are working closely with suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical suppliers which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient.

In addition, continued hostilities related to the Russian invasion of Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors and other factors, combined with volatile commodity prices, and declining business and consumer confidence may contribute to an economic slowdown and a recession. Recent growing concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our business, financial condition and results of operations.

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 continue to issue securities to raise capital. We may also continue to 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 party 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.

In January 2022, we received a Notice of Violation from the EPA related to the CAA. The enforcement action will likely result in monetary sanctions yet-to-be specified and corrective actions, which may increase our development costs and/or operating costs. We are unable to predict the ultimate outcome of this matter at this time, however, we believe that any penalties, mitigation costs, or corrective actions that may result from this matter will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

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."

Holders

As of February 17, 2023 the Company had approximately 1,083 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date. However, we continuously monitor many internal and external factors as we consider when, or if, we should implement shareholder return programs. These factors include our current and projected financial performance; our debt metrics, covenants and absolute amounts borrowed; commodity price outlooks; cash requirements; corporate and strategic plans; and macroeconomic indicators. Ultimately, the timing, amount and form of shareholder return programs, if any, 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.

Performance Graph

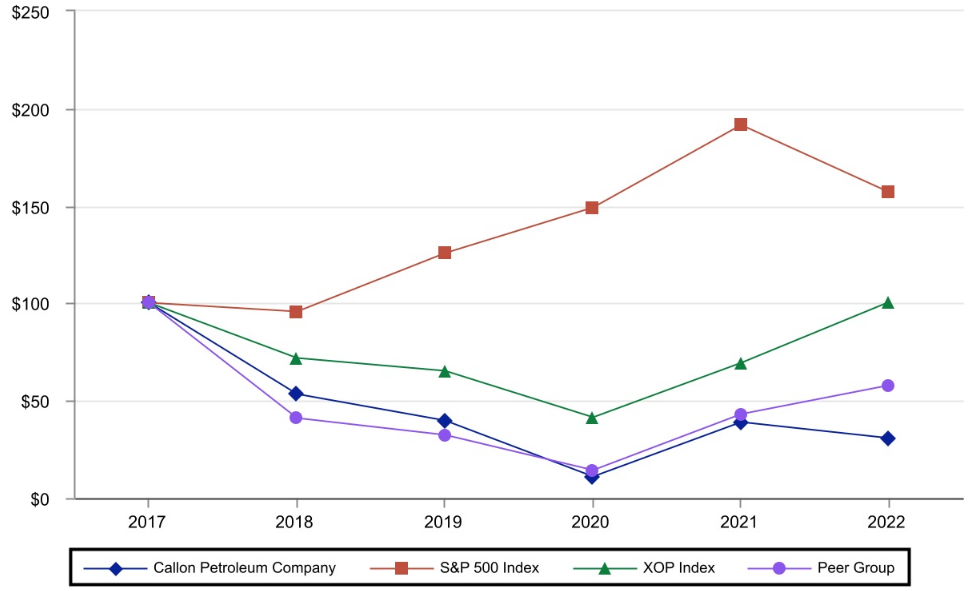
The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to a broad-based stock performance index and an industry specific stock index. The information is included for historical comparative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

In 2022, the Company chose to compare its cumulative total return against a published industry index, the Standard & Poor's Oil & Gas Exploration and Production Select Industry Index ("XOP Index"), instead of a Company selected peer group. The XOP Index includes a larger group of peers to align with the industry and provide a broader comparison of stock price performance. The Company's previous peer group consisted of Magnolia Oil & Gas Corporation, Matador Resources Company, PDC Energy, Inc., Permian Resources Corporation, Ranger Oil Corporation, SM Energy Company and Vital Energy, Inc.

The stock price performance graph 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"), a broad market index, the XOP Index, an index focused on the U.S. oil and gas exploration and production industry, and the previous peer group to which we compare our performance from December 31, 2017 through December 31, 2022. The Company's historical stock prices used in the graph below have been retroactively adjusted to reflect the Company's 1-for-10 reverse stock split effective August 7, 2020.

The stock price 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 or the Exchange Act, 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, 2022



ITEM 6. Reserved

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

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.

A discussion and analysis of the Company's financial condition and results of operations for the year ended December 31, 2020 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, 2021, which was filed with the SEC on February 24, 2022.

General

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 in South Texas. 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 in 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.

Financial and Operational Highlights

For discussion of our significant financial and operational highlights for the year ended December 31, 2022, please see "Part I. Items 1 and 2. Business and Properties — Overview — Major Developments in 2022".

Results of Operations

Production

	Years Ended December 31,			
	2022	**2021**	**$ Change**	**% Change**
Total production				
Oil (MBbls)				
Permian	18,041	14,475	3,566	25 %
Eagle Ford	5,598	7,749	(2,151)	(28 %)
Total oil	23,639	22,224	1,415	6 %
Natural gas (MMcf)				
Permian	35,519	29,682	5,837	20 %
Eagle Ford	6,108	7,704	(1,596)	(21 %)
Total natural gas	41,627	37,386	4,241	11 %
NGLs (MBbls)				
Permian	6,424	5,155	1,269	25 %
Eagle Ford	1,052	1,284	(232)	(18 %)
Total NGLs	7,476	6,439	1,037	16 %
Total production (MBoe)				
Permian	30,385	24,577	5,808	24 %
Eagle Ford	7,668	10,317	(2,649)	(26 %)
Total barrels of oil equivalent	**38,053**	**34,894**	**3,159**	**9 %**
Total daily production (Boe/d)	**104,254**	**95,599**	**8,655**	**9 %**
Oil as % of total daily production	62 %	64 %		(2 %)
Natural gas as % of total daily production	18 %	18 %		— %
NGLs as % of total daily production	20 %	18 %		2 %

The increase in production for the year ended December 31, 2022 compared to the same period of 2021 was primarily due to new wells acquired in the Primexx Acquisition as well as new wells placed on production, partially offset by normal production decline as well as non-core asset divestitures which occurred primarily in the fourth quarter of 2021.

Pricing

	Years Ended December 31,			
	2022	2021	$ Change	% Change
Benchmark prices [1]				
WTI (per Bbl)	$94.26	$67.94	$26.32	39 %
Henry Hub (per Mcf)	6.54	3.72	2.82	76 %
Average realized sales price (excluding impact of derivative settlements)				
Oil (per Bbl)				
Permian	$95.58	$68.20	$27.38	40 %
Eagle Ford	96.15	68.27	27.88	41 %
Total oil	95.72	68.22	27.50	40 %
Natural gas (per Mcf)				
Permian	5.44	3.69	1.75	47 %
Eagle Ford	6.47	4.13	2.34	57 %
Total natural gas	5.59	3.78	1.81	48 %
NGL (per Bbl)				
Permian	35.18	30.60	4.58	15 %
Eagle Ford	32.80	28.12	4.68	17 %
Total NGL	34.84	30.11	4.73	16 %
Total average realized sales price (per Boe)				
Permian	70.55	51.05	19.50	38 %
Eagle Ford	79.84	57.86	21.98	38 %
Total average realized sales price	**$72.42**	**$53.06**	**$19.36**	**36 %**

(1) Reflects calendar average daily spot market prices.

Revenues

	Oil	Natural Gas	NGLs	Total
	(In thousands)			
Revenues for the year ended December 31, 2021 [1]	**$1,516,225**	**$141,493**	**$193,861**	**$1,851,579**
Volume increase	96,538	16,051	31,221	143,810
Price increase	649,884	75,137	35,390	760,411
Net increase	746,422	91,188	66,611	904,221
Revenues for the year ended December 31, 2022 [1]	**$2,262,647**	**$232,681**	**$260,472**	**$2,755,800**
Percent of total revenues	82 %	8 %	10 %	

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

Operating Expenses

Lease Operating Expenses

	Years Ended December 31,							
	2022		2021		Total Change		Boe Change	
	Amount	Per Boe	Amount	Per Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Permian	$218,040	$7.18	$129,563	$5.27	$88,477	68 %	$1.91	36 %
Eagle Ford	72,446	9.45	73,578	7.13	(1,132)	(2 %)	2.32	33 %
Lease operating	**$290,486**	**$7.63**	**$203,141**	**$5.82**	**$87,345**	**43 %**	**$1.81**	**31 %**

The increase in lease operating expenses, as well as lease operating expenses per Boe, for the year ended December 31, 2022 compared to the same period of 2021 was primarily due to the increase in production from wells acquired in the Primexx Acquisition, increases in certain operating expenses such as fuel, power and chemicals, and overall cost inflation.

Production and Ad Valorem Taxes

	Years Ended December 31,							
	2022		2021		Total Change		Boe Change	
	Amount	Per Boe	Amount	Per Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Permian	$122,957	$4.05	$67,596	$2.75	$55,361	82 %	$1.30	47 %
Eagle Ford	36,963	4.82	32,564	3.16	4,399	14 %	1.66	53 %
Production and ad valorem taxes	**$159,920**	**$4.20**	**$100,160**	**$2.87**	**$59,760**	**60 %**	**$1.33**	**46 %**
Production and ad valorem taxes as a percentage of total revenues	5.8%		5.4%			0.4%		

The increase in production and ad valorem taxes for the year ended December 31, 2022 compared to the same period of 2021 was primarily related to a 49% increase in total revenues which increased production taxes, as well as an increase in ad valorem taxes due to higher property tax valuations as a result of higher commodity prices during 2021 compared to 2020. The increase in production and ad valorem taxes as a percentage of total revenues for the year ended December 31, 2022 compared to the same period of 2021 was primarily due to an increase in ad valorem taxes during the year ended December 31, 2022 as discussed above.

Gathering, Transportation and Processing Expenses

	Years Ended December 31,							
	2022		2021		Total Change		Boe Change	
	Amount	Per Boe	Amount	Per Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Permian	$82,459	$2.71	$62,371	$2.54	$20,088	32 %	$0.17	7 %
Eagle Ford	14,443	1.88	18,599	1.80	(4,156)	(22 %)	0.08	4 %
Gathering, transportation and processing	**$96,902**	**$2.55**	**$80,970**	**$2.32**	**$15,932**	**20 %**	**$0.23**	**10 %**

The increase in gathering, transportation and processing expenses for the year ended December 31, 2022 compared to the same period of 2021 was primarily related to the 9% increase in production volumes between the two periods as well as rate adjustments on certain firm transportation agreements. See "Note 17 – Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for additional details on our firm transportation agreements.

Depreciation, Depletion and Amortization ("DD&A")

The following table sets forth the components of our DD&A for the periods indicated:

	Years Ended December 31,							
	2022		2021		Total Change		Boe Change	
	Amount	Per Boe	Amount	Per Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
DD&A of evaluated oil and gas properties	$457,873	$12.03	$347,199	$9.95	$110,674	32 %	$2.08	21 %
Depreciation of other property and equipment	1,685	0.04	1,950	0.06	(265)	(14 %)	(0.02)	(33 %)
Amortization of other assets	2,962	0.08	3,664	0.10	(702)	(19 %)	(0.02)	(20 %)
Accretion of asset retirement obligations	3,997	0.11	3,743	0.11	254	7 %	—	— %
DD&A	**$466,517**	**$12.26**	**$356,556**	**$10.22**	**$109,961**	**31 %**	**$2.04**	**20 %**

The increase in DD&A for the year ended December 31, 2022 compared to the same period of 2021 was primarily attributable to a production increase of 9% as well as the addition of properties acquired in the Primexx Acquisition.

General and Administrative, Net of Amounts Capitalized ("G&A")

	Years Ended December 31,							
	2022		2021		Total Change		Boe Change	
	Amount	Per Boe	Amount	Per Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
General and administrative	$57,393	$1.51	$50,483	$1.45	$6,910	14 %	$0.06	4 %

The increase in G&A for the year ended December 31, 2022 compared to the same period of 2021 was primarily due to an increase in employee-related costs between the two periods, partially offset by a decrease in the fair value of cash settled awards as a result of the decrease in our stock price between the two periods.

Other Income and Expenses

Interest Expense, Net of Capitalized Amounts

The following table sets forth the components of our interest expense, net of capitalized amounts for the periods indicated:

	Years Ended December 31,		
	2022	2021	Change
		(In thousands)	
Interest expense on Senior Unsecured Notes	$124,694	$107,784	$16,910
Interest expense on Second Lien Notes	13,825	43,791	(29,966)
Interest expense on credit facility	36,860	31,647	5,213
Amortization of debt issuance costs, premiums and discounts	12,333	18,309	(5,976)
Other interest expense	80	128	(48)
Capitalized interest	(108,125)	(99,647)	(8,478)
Interest expense, net of capitalized amounts	**$79,667**	**$102,012**	**($22,345)**

The decrease in interest expense, net of capitalized amounts for the year ended December 31, 2022 compared to the same period of 2021 is primarily due to the reduction in interest expense and the write-off of the discount associated with the Second Lien Notes exchange in November 2021 and an increase in capitalized interest, partially offset by an increase in interest expense related to the issuance of the 8.0% Senior Notes in July 2021 and the issuance of the 7.5% Senior Notes in June 2022. See "Note 7 – Borrowings" of the Notes to Consolidated Financial Statements for additional information regarding the Second Lien Notes exchange.

Loss on Derivative Contracts

The net loss on derivative contracts for the periods indicated includes the following:

	Years Ended December 31,		
	2022	2021	Change
		(In thousands)	
Loss on oil derivatives	$287,379	$429,156	($141,777)
Loss on natural gas derivatives	38,803	33,621	5,182
Loss on NGL derivatives	4,771	6,768	(1,997)
Gain on contingent consideration arrangements	—	(2,635)	2,635
Loss on September 2020 Warrants liability [(1)]	—	55,390	(55,390)
Loss on derivative contracts	**$330,953**	**$522,300**	**($191,347)**

(1) A detailed discussion of our September 2020 Warrants can be found in "Part II, Item 8. Financial Statements and Supplementary Data, Note 7 – Borrowings" of our Annual Report on Form 10-K for the year ended December 31, 2021, which was filed with the SEC on February 24, 2022.

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. For the year ended December 31, 2022, we recognized loss on extinguishment of debt of $45.7 million as a result of the redemptions of the 6.125% Senior Notes and Second Lien Notes and the termination of our Prior Credit Facility.

For the year ended December 31, 2021, we recognized a net loss on extinguishment of debt of $41.0 million as a result of the exchange of Second Lien Notes for 5.5 million shares of our common stock and the redemption of all of our 6.25% Senior Notes.

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 years ended December 31, 2022 and 2021, we recorded sales of purchased oil and gas of $475.2 million and $193.5 million, respectively, and cost of purchased oil and gas of $478.4 million and $201.1 million, respectively, related to commodities purchased from third parties and sold to our customers. See "Note 3 – Revenue Recognition" of the Notes to our Consolidated Financial Statements for additional information.

Income Tax Expense. We recorded income tax expense of $11.8 million for the year ended December 31, 2022 compared to $0.2 million for the same period of 2021. Since the second quarter of 2020, we have concluded that it is more likely than not that the net deferred tax assets will not be realized and have recorded a full valuation allowance against our deferred tax assets. As long as we continue to conclude that the valuation allowance is necessary, we do not expect to have significant deferred income tax expense or benefit. See "Note 12 – Income Taxes" of the Notes to our Consolidated Financial Statements for further discussion.

Liquidity and Capital Resources

Outlook. Oil prices continue to remain volatile, as the NYMEX oil price closed the year down over 30% from the highs seen during the second quarter of 2022. We expect to continue to see volatility in oil prices, as well as natural gas and NGL prices. We also expect to continue to experience inflationary cost pressures in 2023 on many different service items including labor, materials, power and equipment.

2023 Capital Budget and Funding Strategy. Our primary uses of capital are for the exploration and development of our oil and natural gas properties. Our 2023 Capital Budget has been established at $1.0 billion, with over 80% allocated towards development in the Permian with the balance towards development in the Eagle Ford. Because we are the operator of a high percentage of our properties, we can control the well design and the development pace associated with our capital expenditures. We plan to execute a moderated capital expenditure program through reduced reinvestment rates and balanced capital deployment for more consistent cash flow generation and to drive capital efficiency through an enhanced multi-zone, scaled development program. See “Items 1 and 2. Business and Properties — Capital Budget” for additional details.

The following table is a summary of our 2022 capital expenditures(1):

	Three Months Ended				Year Ended
	March 31, 2022	June 30, 2022	September 30, 2022	December 31, 2022	December 31, 2022
	(In millions)				
Operational capital	$157.4	$237.8	$254.6	$191.7	$841.5
Capitalized interest	25.5	26.3	27.5	28.8	108.1
Capitalized G&A	11.6	11.3	12.7	13.2	48.8
Total	**$194.5**	**$275.4**	**$294.8**	**$233.7**	**$998.4**

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

We believe that existing cash and cash equivalents, cash flows from operations and available borrowings under our credit facility will be sufficient to support working capital, capital expenditures and other cash requirements for at least the next 12 months and, based on our current expectations, for the foreseeable future thereafter. Our future capital requirements, both near-term and long-term, will depend on many factors, including, but not limited to, 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.

Historically, our primary sources of capital have been cash flows from operations, borrowings under our credit facility, proceeds from the issuance of debt securities and public equity offerings, and non-core asset dispositions. We regularly consider which resources, including cash flows from operations and debt and equity financings, are available to meet our future financial obligations, planned capital expenditures and liquidity requirements. In addition, 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.

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.

Overview of Cash Flow Activities. For the year ended December 31, 2022, cash and cash equivalents decreased $6.5 million to $3.4 million compared to $9.9 million at December 31, 2021.

	Years Ended December 31,	
	2022	2021
	(In thousands)	
Net cash provided by operating activities	$1,501,517	$974,143
Net cash used in investing activities	(999,027)	(876,400)
Net cash used in financing activities	(508,977)	(108,097)
Net change in cash and cash equivalents	**($6,487)**	**($10,354)**

Operating Activities. Net cash provided by operating activities was $1.5 billion and $974.1 million for the years ended December 31, 2022 and 2021, respectively. The increase in net cash provided by operating activities was primarily attributable to the following:

- An increase of $904.2 million in total revenue, which excludes sales of oil and gas purchased from third parties and sold to our customers, primarily driven by a 36% increase in total average realized sales price, as well as a 9% increase in production volumes; offset by
- An increase in cash outflows of $127.0 million related to timing of working capital payments and receipts; and
- Increase in cash paid for commodity derivative settlements of $98.6 million.

Investing Activities. Net cash used in investing activities was $999.0 million and $876.4 million for the years ended December 31, 2022 and 2021, respectively. The increase in investing activities was primarily attributable to the following:

- An increase in operational capital expenditures of $414.5 million; and
- A decrease in sales of non-core oil and gas properties of $161.0 million; offset by
- A decrease in acquisitions of $465.5 million due to the Primexx acquisition during 2021.

Financing Activities. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our credit facility, term debt and equity offerings. For the year ended December 31, 2022, net cash used in financing activities was $509.0 million compared to $108.1 million during 2021. The increase in net cash used in financing activities was primarily attributable to the following:

- Redemption of the Second Lien Notes of $339.5 million; and
- Repayments in excess of borrowings of $82.0 million on the credit facility.

See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information on our debt transactions.

Credit Facility. As of December 31, 2022, our Credit Facility had a maximum credit amount of $5.0 billion, a borrowing base of$2.0 billion and an elected commitment amount of $1.5 billion, with borrowings outstanding of $503.0 million at a weighted-average interest rate of 6.56%, and letters of credit outstanding of $16.4 million.

See “Note 7 – Borrowings” for additional information related to the Prior Credit Facility and the Credit Facility.

Income Taxes. 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 a combined annual limitation under Internal Revenue Code (the “IRC”) Section 382 in the amount of $32.2 million, which is comprised of $15.7 million of Carrizo’s NOLs and $16.5 million of Callon’s NOLs. At December 31, 2022, the Company had approximately $1.7 billion of NOLs, some of which i) are subject to annual limitation under Section 382, ii) are subject to the IRC’s 80% taxable income limitation rule, or iii) expire between 2034 and 2037, as summarized in the table below.

Subject to Annual Limitation Under Section 382	**Subject to IRC’s 80% Taxable Income Limitation**	**Years of Expiration**	**NOL Balance**
			(In millions)
Yes	Yes	N/A	$647.6
No	Yes	N/A	666.5
Yes	No	2034 to 2037	399.2
			$1,713.3

Additionally, the Company also has a net interest expense carryforward of $355.4 million under Section 163(j) of the Code, which has an indefinite life.

Material Cash Requirements

As of December 31, 2022, we have financial obligations associated with our outstanding long-term debt, including interest payments and principal repayments. See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for further discussion of the contractual commitments under our debt agreements, including the timing of principal repayments. Additionally, we have operational obligations associated with long-term, non-cancelable leases, drilling rig contracts, frac service contracts, gathering, processing and transportation service agreements and other purchase obligations as well as estimates of future asset retirement obligations. See “Note 14 – Asset Retirement Obligations” and “Note 17 – Commitments and Contingencies” of the Notes to our Consolidated Financial Statements for additional details.

We estimate that the combination of our sources of capital, as discussed above, will continue to be adequate to fund our short- and long-term contractual obligations.

Critical Accounting Estimates

For discussion regarding our significant accounting policies, see "Note 2 – Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements. We have outlined below the policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

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 and 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, and litigation 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. Capitalized oil and gas property costs are amortized on an equivalent unit-of-production method whereby the 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. Each quarter, a full cost ceiling test is performed to determine whether an impairment to our evaluated oil and gas properties should be recorded.

The process of estimating proved oil and gas reserves requires that our independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. Additionally, operating costs, production and ad valorem taxes, and future development costs are estimated based on current costs. A significant change to our estimated volumes of oil and gas reserves as well as changes to the estimates of prices and costs could have an impact on the depletion rate calculation as well as the estimated future net revenues used in the cost center ceiling.

The table below presents various pricing scenarios to demonstrate the sensitivity of our December 31, 2022 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, 2022 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, 2022 that may require revisions to estimates of proved reserves. 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."

	12-Month Average Realized Prices		Excess 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, 2022 Actual	$95.02	$5.75	$5,111	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$104.39	$6.38	$6,323	$1,212
Crude Oil and Natural Gas -10%	$85.65	$5.11	$3,899	($1,212)
Crude Oil Price Sensitivity				
Crude Oil +10%	$104.39	$5.75	$6,191	$1,080
Crude Oil -10%	$85.65	$5.75	$4,031	($1,080)
Natural Gas Price Sensitivity				
Natural Gas +10%	$95.02	$6.38	$5,243	$132
Natural Gas -10%	$95.02	$5.11	$4,979	($132)

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. 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.

Our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments as a result of the volatility of oil and gas prices. See "Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk" for the impact on the fair values of our derivative instruments assuming a 10% increase and decrease in the underlying forward oil and gas price curves as of December 31, 2022.

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, 2022, driven primarily by impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the fourth quarter of 2020. This limits the ability to consider other subjective evidence such as our potential for future growth. Since the second quarter 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 have recorded a valuation allowance, reducing the net deferred tax assets as of December 31, 2022 to zero.

We currently believe it is reasonably possible we could achieve a three-year cumulative level of profitability within the next 12 months, which would enhance our ability to conclude that it is more likely than not that the deferred tax assets would be realized and support a release of substantially all or a portion of the valuation allowance. However, the exact timing and amount of the release is unknown at this time. We will continue to evaluate whether the valuation allowance is needed in future reporting periods based on available information each reporting period. 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. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income. See "Note 12 – Income Taxes" of the Notes to our Consolidated Financial Statements for additional discussion.

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.

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 volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, government actions, economic conditions, and weather conditions.

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 and takes into account our view of current and future market conditions in order to provide greater certainty of cash flows to meet our debt service costs and capital program. We generally hedge 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.

We may utilize fixed price swaps, which reduce our exposure to decreases in commodity prices, but limit 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 or 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.

Additionally, we may enter into basis swap contracts which fix the basis differentials between the index price at which the Company sells its production and the relevant NYMEX benchmark price used in swap or collar contracts.

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.

The following table sets forth the fair values of our commodity derivative instruments as of December 31, 2022 as well as the impact on the fair values assuming a 10% increase and decrease in the underlying forward oil and gas price curves as of December 31, 2022:

	Year Ended December 31, 2022		
	Oil	**Natural Gas**	**Total**
		(In thousands)	
Fair value asset (liability) as of December 31, 2022 (1)	($18,077)	$18,261	$184
Impact of a 10% increase in forward commodity prices	($58,535)	$17,539	($40,996)
Impact of a 10% decrease in forward commodity prices	$20,080	$19,057	$39,137

(1) Spot prices for oil and natural gas were $80.33 and $4.48, respectively, as of December 30, 2022.

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, 2022, we had $503.0 million outstanding under the Credit Facility with a weighted average interest rate of 6.56%. An increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our annual interest expense of approximately $5.0 million, based on the balance outstanding as of December 31, 2022. 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, natural gas and NGL production, joint interest receivables and receivables resulting from derivative financial contracts.

For the year ended December 31, 2022, two purchasers each accounted for more than 10% of our oil, natural gas, and NGL revenues. 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 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.

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. As of December 31, 2022, our joint interest receivables were approximately $16.8 million and we had no material past due balances.

See “Note 8 – Derivative Instruments and Hedging Activities” of the Notes to our Consolidated Financial Statements for discussion of counterparty credit risk associated with our commodity derivative arrangements.

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, 2022 and 2021, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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 23, 2023 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 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 matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

The development of estimated proved reserves used in the calculation of depletion, depreciation and amortization expense under the full cost method of accounting

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. 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. 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 necessary to estimate the volumes and future net revenues of the Company's proved reserves require a high degree of subjectivity and could have a significant impact on the measurement of depletion expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of controls relating to management’s estimation of proved reserves for the purpose of estimating depletion expense.
- 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 development 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:
    - We compared the estimated pricing differentials used in the reserve report to prices realized by the Company related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials
    - We tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs
    - We evaluated the method used to determine estimated future development costs used in the reserve report and compared management’s estimate to amounts expended for recently drilled and completed wells to ascertain its reasonableness
    - We tested the working and net revenue interests used in the reserve report by inspecting land and division order records
    - We 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 and intent to develop the proved undeveloped properties, and
    - We applied analytical procedures to production forecasts in the reserve report 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 23, 2023

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, 2022, 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, 2022, 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, 2022, and our report dated February 23, 2023 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. 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 23, 2023

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

	December 31,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$3,395	$9,882
Accounts receivable, net	237,128	232,436
Fair value of derivatives	21,332	22,381
Other current assets	35,783	30,745
Total current assets	297,638	295,444
Oil and natural gas properties, full cost accounting method:		
Evaluated properties, net	4,023,603	3,352,821
Unevaluated properties	1,711,306	1,812,827
Total oil and natural gas properties, net	5,734,909	5,165,648
Other property and equipment, net	26,152	28,128
Deferred financing costs	18,822	18,125
Other assets, net	68,560	40,158
Total assets	**$6,146,081**	**$5,547,503**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$536,233	$569,991
Fair value of derivatives	16,197	185,977
Other current liabilities	150,384	116,523
Total current liabilities	702,814	872,491
Long-term debt	2,241,295	2,694,115
Asset retirement obligations	53,892	54,458
Fair value of derivatives	13,415	11,409
Other long-term liabilities	49,243	49,262
Total liabilities	**3,060,659**	**3,681,735**
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value, 130,000,000 and 78,750,000 shares authorized; 61,621,518 and 61,370,684 shares outstanding, respectively	616	614
Capital in excess of par value	4,022,194	4,012,358
Accumulated deficit	(937,388)	(2,147,204)
Total stockholders' equity	**3,085,422**	**1,865,768**
Total liabilities and stockholders' equity	**$6,146,081**	**$5,547,503**

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

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

	For the Year Ended December 31,		
	2022	**2021**	**2020**
Operating Revenues:			
Oil	$2,262,647	$1,516,225	$850,667
Natural gas	232,681	141,493	51,866
Natural gas liquids	260,472	193,861	81,295
Sales of purchased oil and gas	475,164	193,451	49,319
Total operating revenues	3,230,964	2,045,030	1,033,147
Operating Expenses:			
Lease operating	290,486	203,141	194,101
Production and ad valorem taxes	159,920	100,160	62,638
Gathering, transportation and processing	96,902	80,970	77,309
Cost of purchased oil and gas	478,445	201,088	51,766
Depreciation, depletion and amortization	466,517	356,556	480,631
General and administrative	57,393	50,483	37,187
Impairment of evaluated oil and gas properties	—	—	2,547,241
Merger, integration and transaction	769	14,289	28,482
Total operating expenses	1,550,432	1,006,687	3,479,355
Income From Operations	**1,680,532**	**1,038,343**	**(2,446,208)**
Other (Income) Expenses:			
Interest expense, net of capitalized amounts	79,667	102,012	94,329
Loss on derivative contracts	330,953	522,300	27,773
(Gain) loss on extinguishment of debt	45,658	41,040	(170,370)
Other (income) expense	2,645	7,660	13,627
Total other (income) expense	458,923	673,012	(34,641)
Income (Loss) Before Income Taxes	**1,221,609**	**365,331**	**(2,411,567)**
Income tax expense	(11,793)	(180)	(122,054)
Net Income (Loss)	**$1,209,816**	**$365,151**	**($2,533,621)**
Net Income (Loss) Per Common Share:			
Basic	$19.63	$7.51	($63.79)
Diluted	$19.54	$7.26	($63.79)
Weighted Average Common Shares Outstanding:			
Basic	61,620	48,612	39,718
Diluted	61,904	50,311	39,718

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

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(In thousands)

	Common Stock		Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	$			
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 units	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**
Net income	—	—	—	365,151	365,151
Restricted stock units	156	2	10,949	—	10,951
Warrant exercises	6,913	69	134,748	—	134,817
Common stock issued for Primexx Acquisition	9,030	90	420,610	—	420,700
Common stock issued for Second Lien Notes Exchange	5,513	55	223,092	—	223,147
Balance at 12/31/2021	**61,371**	**$614**	**$4,012,358**	**($2,147,204)**	**$1,865,768**
Net income	—	—	—	1,209,816	1,209,816
Restricted stock units	266	3	8,735	—	8,738
Common stock issued for Primexx Acquisition	(15)	(1)	1,101	—	1,100
Balance at 12/31/2022	**61,622**	**$616**	**$4,022,194**	**($937,388)**	**$3,085,422**

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,		
	2022	2021	2020
Cash flows from operating activities:			
Net income (loss)	$1,209,816	$365,151	($2,533,621)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	466,517	356,556	480,631
Impairment of evaluated oil and gas properties	—	—	2,547,241
Amortization of non-cash debt related items, net	5,280	10,124	3,901
Deferred income tax expense	4,279	—	118,607
Loss on derivative contracts	330,953	522,300	27,773
Cash received (paid) for commodity derivative settlements, net	(493,714)	(395,097)	98,870
(Gain) loss on extinguishment of debt	45,658	41,040	(170,370)
Non-cash expense related to share-based awards	2,507	12,923	2,663
Other, net	7,136	11,037	7,087
Changes in current assets and liabilities:			
Accounts receivable	(3,480)	(86,402)	75,770
Other current assets	(15,392)	(10,399)	(6,550)
Accounts payable and accrued liabilities	(58,043)	146,910	(92,227)
Net cash provided by operating activities	**1,501,517**	**974,143**	**559,775**
Cash flows from investing activities:			
Capital expenditures	(992,985)	(578,487)	(664,231)
Acquisition of oil and gas properties	(28,253)	(493,732)	(12,923)
Proceeds from sales of assets	27,093	188,101	178,970
Cash paid for settlement of contingent consideration arrangement	(19,171)	—	(40,000)
Other, net	14,289	7,718	8,301
Net cash used in investing activities	**(999,027)**	**(876,400)**	**(529,883)**
Cash flows from financing activities:			
Borrowings on credit facility	3,286,000	2,140,500	5,353,000
Payments on credit facility	(3,568,000)	(2,340,500)	(5,653,000)
Issuance of senior notes	600,000	650,000	—
Redemption of senior notes	(467,287)	(542,755)	—
Redemption of 9.0% Second Lien Senior Secured Notes due 2025	(339,507)	—	—
Issuance of 9.0% Second Lien Senior Secured Notes due 2025	—	—	300,000
Discount on the issuance of 9.0% Second Lien Senior Secured Notes due 2025	—	—	(35,270)
Issuance of September 2020 Warrants	—	—	23,909
Payment of deferred financing costs	(21,898)	(12,672)	(10,811)
Other, net	1,715	(2,670)	(825)
Net cash used in financing activities	**(508,977)**	**(108,097)**	**(22,997)**
Net change in cash and cash equivalents	(6,487)	(10,354)	6,895
Balance, beginning of period	9,882	20,236	13,341
Balance, end of period	**$3,395**	**$9,882**	**$20,236**

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 focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. 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.

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 in South Texas. 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, 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, 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. Such reclassifications did not have a material impact on prior period financial statements. The Company evaluates events subsequent to the balance sheet date through the date the financial statements are issued.

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, and litigation 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 oil, natural gas and NGL revenues for at least one of the periods presented:

	Years Ended December 31,		
	2022 (1)	**2021 (1)**	**2020 (1)**
Valero Marketing and Supply Company	15%	13%	23%
Rio Energy International, Inc.	12	*	*
Shell Trading Company	*	20	31
Trafigura Trading, LLC	*	15	*
Occidental Energy Marketing, Inc.	*	13	*

(1) The customers that represented over 10% of the Company's sales of purchased oil and gas were Vitol Inc., for the years ended December 31, 2022, 2021 and 2020, and Plains Marketing, L.P., for the year ended December 31, 2022.

* - Less than 10% for the applicable year.

See "Note 8 – Derivative Instruments and Hedging Activities" for discussion of credit risk related with the Company's commodity derivative counterparties.

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 divestitures 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, 2022, 2021 and 2020, 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, natural gas, and NGLs.

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 include 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 when the proved reserves have been assigned to 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, among other things, the exploration program and intent to drill, as well as remaining lease term to determine if these costs have been impaired. 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.

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 12-Month Average Realized Price of oil, NGLs, and natural gas, 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. The Company did not recognize impairments of evaluated oil and gas properties for the years ended December 31, 2022 and 2021. Primarily as a result of a31% 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 ended December 31, 2020.

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

Deferred Financing Costs

Deferred financing costs associated with the Unsecured Senior Notes and previously with the Second Lien Notes, both defined below, are classified as a reduction of the related 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 Credit Facility, as defined below, 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. The Company does not enter into commodity derivative instruments for speculative or trading purposes. 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 (“ISDA Agreements”), which provide for net settlement over the term of the contract and in the event of default or termination of the contract.

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.

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 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.

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.

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. 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.

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" and together with Cash-Settled RSU Awards, the "Cash-Settled Awards") are remeasured at fair value at the end of each reporting period with the change in fair value recorded as share-based compensation expense. 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 outstanding will expire between two and three 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,		
	2022	2021	2020
	(In thousands)		
Interest paid, net of capitalized amounts	$82,390	$85,042	$91,269
Income taxes paid (1)	—	—	—
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$7,096	$26,681	$44,314
Investing cash flows from operating leases	32,060	18,598	24,234
Non-cash investing and financing activities:			
Change in accrued capital expenditures	$12,096	$63,444	($64,465)
Change in asset retirement costs	6,500	2,905	8,605
ROU assets obtained in exchange for lease liabilities:			
Operating leases	$56,291	$24,301	$8,070
Financing leases	—	—	—

(1) The Company did not pay any federal income tax for any of the years in the three-year period ending December 31, 2022. For the years ended December 31, 2022, 2021, and 2020, the Company paid approximately $0.2 million, $3.2 million, and $1.5 million, respectively, in state income taxes.

Earnings per Share

The Company's basic net income (loss) per common share is based on the weighted average number of shares of common stock outstanding for the period. Diluted net income (loss) 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 net loss per common share exists, all potentially dilutive common shares outstanding are anti-dilutive and are 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, and all of the Company's operations are located in the United States.

Recently Adopted Accounting Standards

Debt. In August 2020, the FASB issued ASU No. 2020-06, Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40) ("ASU 2020-06"). ASU 2020-06 was issued to reduce the complexity associated with accounting for certain financial instruments with characteristics of liabilities and equity. The guidance is to be applied using either a modified retrospective or a fully retrospective method. ASU 2020-06 is effective for fiscal years beginning after December 15, 2021, with early adoption permitted. The Company adopted ASU 2020-06 on January 1, 2022. The adoption of ASU 2020-06 did not have a material impact to the Company's consolidated financial statements or disclosures.

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. In December 2022, the FASB issued ASU 2022-06 which extend the effective date through December 31, 2024. As of December 31, 2022, 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 Credit Agreement (as defined below) recently entered into which replaced all provisions and related definitions regarding LIBOR with SOFR.

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. The Company has certain oil sales that occur at market locations downstream of the production area. Given the structure of these arrangements and where control transfers, the Company separately recognizes fees and other deductions incurred prior to control transfer as "Gathering, transportation and processing" in its consolidated statements of operations.

Natural gas and NGL sales

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 either remits proceeds to the Company for the resulting sale of NGLs and residue gas or, in take in-kind arrangements, provides the Company the resulting NGLs and/or residue gas for sale to downstream customers. 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 the Company maintains control through processing or has 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. The Company recognizes revenue when control transfers to the purchaser at the delivery point based on the contractual index price received.

The Company 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.

Oil and gas purchase and sale arrangements

The Company proactively evaluates development plans and looks to enter into pipeline transportation contracts to mitigate market exposures and help ensure certainty of flow for its oil and gas production, in some cases multiple years in advance of development. Additionally, as the Company looks to optimize its operations and reduce exposures, in certain instances, the Company purchases oil and gas from third parties which is utilized to fulfill portions of its pipeline commitments. 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, 2022 and 2021 of $174.1 million and $171.8 million, respectively, and are presented in "Accounts receivable, net" in the consolidated balance sheets.

Note 4 – Acquisitions and Divestitures

2022 Acquisitions and Divestitures

The Company did not have any material acquisitions or divestitures for the year ended December 31, 2022.

2021 Acquisitions and Divestitures

Primexx Acquisition

On October 1, 2021, the Company closed on the acquisition of certain producing oil and gas properties, undeveloped acreage and associated infrastructure assets in the Delaware Basin from Primexx Resource Development, LLC ("Primexx") and BPP Acquisition, LLC ("BPP") for an adjusted purchase price of approximately $444.8 million in cash, inclusive of the deposit paid at signing, 8.84 million shares of the Company's common stock and approximately $25.2 million paid upon final closing for total consideration of $877.0 million (the "Primexx Acquisition"). The Company funded the cash portion of the total consideration with borrowings under its credit facility. Of the 8.84 million shares of the Company's common stock issued upon closing,2.6 million shares were held in escrow pursuant to the purchase and sale agreements with Primexx and BPP (collectively, the "Primexx PSAs"). Pursuant to the Primexx PSAs, 1.3 million of the shares held in escrow were released to the sellerssix months after the closing date, which was on April 1, 2022. In early October 2022, the remaining 1.2 million shares were released to the sellers, net of shares that were released to the Company for the satisfaction of indemnification claims made under the Primexx PSAs and subsequently retired.

Also, pursuant to the Primexx PSAs, certain interest owners exercised their option to sell their interest in the properties included in the Primexx Acquisition to the Company for consideration structured similarly to the Primexx Acquisition, for an incremental purchase price totaling approximately $31.8 million, net of customary purchase price adjustments, of which $22.4 million closed during the fourth quarter of 2021 and the remaining $9.4 million closed during the first quarter of 2022.

The Primexx 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 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 of $908.9 million to the assets acquired and liabilities assumed as of the acquisition date.

	Final Purchase Price Allocation
	(In thousands)
Assets:	
Other current assets	$8,174
Evaluated oil and natural gas properties	695,838
Unevaluated properties	278,370
Total assets acquired	$982,382
Liabilities:	
Suspense payable	$16,447
Other current liabilities	45,745
Asset retirement obligation	1,898
Other long-term liabilities	9,425
Total liabilities assumed	$73,515
Total consideration	$908,867

Approximately $570.7 million of revenues and $141.2 million of direct operating expenses attributed to the Primexx Acquisition were included in the Company's consolidated statements of operations for the year ended December 31, 2022. For the period from the closing date of the Primexx Acquisition on October 1, 2021 through December 31, 2021, approximately $114.3 million of revenues and $32.1 million of direct operating expenses were included in the Company's consolidated statements of operations for the year ended December 31, 2021.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma combined condensed financial data for the years ended December 31, 2021 and 2020 was derived from the historical financial statements of the Company giving effect to the Primexx Acquisition, as if it had occurred on January 1, 2020. The below information reflects pro forma adjustments for the issuance of the Company's common stock and the borrowings under the Credit Facility as total consideration, as well as pro forma adjustments based on available information and certain assumptions that the Company believes provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the Primexx Acquisition.

The pro forma consolidated statements of operations data has been included for comparative purposes only, is not necessarily indicative of the results that might have occurred had the Primexx Acquisition taken place on January 1, 2020 and is not intended to be a projection of future results.

	Years Ended December 31,	
	2021	**2020**
	(In thousands)	
Revenues	$2,294,893	$1,228,735
Income (loss) from operations	1,151,493	(3,072,237)
Net income (loss)	482,690	(3,151,443)
Basic earnings per common share	$8.37	($64.65)
Diluted earnings per common share	$8.13	($64.65)

Non-Core Asset Divestitures

During the second quarter of 2021, the Company completed its divestitures of certain non-core assets in the Delaware Basin for net proceeds of $29.6 million. The divestitures were primarily comprised of natural gas producing properties in the Western Delaware Basin as well as a small undeveloped acreage position.

On November 19, 2021, the Company closed on its divestiture of certain non-core assets in the Eagle Ford Shale, comprised of producing properties as well as an undeveloped acreage position, for net proceeds of $91.9 million.

In the fourth quarter of 2021, the Company closed on the divestiture of certain non-core assets in the Midland Basin, comprised of producing properties as well as an undeveloped acreage position for net proceeds of $30.5 million.

On October 28, 2021, the Company closed on the divestiture of certain non-core water infrastructure for net proceeds of $27.9 million, as well as up to $18.0 million of incremental contingent consideration based on completed lateral length for wells in a specified area.

The aggregate net proceeds for each of the 2021 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.

2020 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 net proceeds of $135.8 million ("ORRI Transaction"), which 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.

Note 5 – Property and Equipment, Net

As of December 31, 2022 and 2021, total property and equipment, net consisted of the following:

	As of December 31,	
	2022	**2021**
Oil and natural gas properties, full cost accounting method	**(In thousands)**	
Evaluated properties	$10,367,478	$9,238,823
Accumulated depreciation, depletion, amortization and impairments	(6,343,875)	(5,886,002)
Evaluated properties, net	4,023,603	3,352,821
Unevaluated properties		
Unevaluated leasehold and seismic costs	1,392,327	1,557,453
Capitalized interest	318,979	255,374
Total unevaluated properties	1,711,306	1,812,827
Total oil and natural gas properties, net	**$5,734,909**	**$5,165,648**
Other property and equipment	$40,530	$58,367
Accumulated depreciation	(14,378)	(30,239)
Other property and equipment, net	**$26,152**	**$28,128**

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $48.8 million, $47.4 million, and $36.2 million for the years ended December 31, 2022, 2021 and 2020, respectively.

The Company capitalized interest costs to unproved properties totaling $108.1 million, $99.6 million and $88.6 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Impairment of Evaluated Oil and Gas Properties

The Company did not recognize impairments of evaluated oil and gas properties for the years ended December 31, 2022 and 2021. Primarily as a result of the significant reduction 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 ended December 31, 2020.

Details of the 12-Month Average Realized Price of oil for the years ended December 31, 2022, 2021, and 2020 are summarized in the table below:

	Years Ended December 31,		
	2022	2021	2020
Impairment of evaluated oil and natural gas properties (In thousands)	**$—**	**$—**	**$2,547,241**
Beginning of period 12-Month Average Realized Price ($/Bbl)	$65.44	$37.44	$53.90
End of period 12-Month Average Realized Price ($/Bbl)	$95.02	$65.44	$37.44
Percent increase (decrease) in 12-Month Average Realized Price	45 %	75 %	(31 %)

Unevaluated property costs not subject to amortization as of December 31, 2022 were incurred in the following periods:

	2022	2021	2020	2019 and Prior	Total
			(In thousands)		
Unevaluated property costs	$141,944	$401,403	$113,078	$1,054,881	$1,711,306

Note 6 – Earnings Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) 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 stock units 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 net loss. 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,		
	2022	2021	2020
	(In thousands, except per share amounts)		
Net Income (Loss)	**$1,209,816**	**$365,151**	**($2,533,621)**
Basic weighted average common shares outstanding	61,620	48,612	39,718
Dilutive impact of restricted stock units	284	296	—
Dilutive impact of warrants	—	1,403	—
Diluted weighted average common shares outstanding	**61,904**	**50,311**	**39,718**
Net Income (Loss) Per Common Share			
Basic	$19.63	$7.51	($63.79)
Diluted	$19.54	$7.26	($63.79)
Restricted stock units (1)	30	7	581
Warrants (1)	455	481	2,564

(1) 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,	
	2022	2021
	(In thousands)	
6.125% Senior Notes due 2024	—	460,241
9.0% Second Lien Senior Secured Notes due 2025	—	319,659
8.25% Senior Notes due 2025	187,238	187,238
6.375% Senior Notes due 2026	320,783	320,783
Senior Secured Revolving Credit Facility due 2027	503,000	785,000
8.0% Senior Notes due 2028	650,000	650,000
7.5% Senior Notes due 2030	600,000	—
Total principal outstanding	**2,261,021**	**2,722,921**
Unamortized premium on 6.125% Senior Notes	—	2,373
Unamortized discount on 9.0% Second Lien Notes	—	(14,852)
Unamortized premium on 8.25% Senior Notes	1,715	2,477
Unamortized deferred financing costs for 9.0% Second Lien Notes	—	(2,910)
Unamortized deferred financing costs for Senior Unsecured Notes	(21,441)	(15,894)
Total carrying value of borrowings (1)	**$2,241,295**	**$2,694,115**

(1) Excludes unamortized deferred financing costs related to the Company's senior secured revolving credit facility of $18.8 million and $18.1 million as of December 31, 2022 and 2021, 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 acquisition of Carrizo Oil & Gas, Inc. (the "Merger" or the "Carrizo Acquisition"), the Company entered into the credit agreement with a syndicate of lenders (the "Prior Credit Facility"). The Prior Credit Facility provided for interest-only payments until December 20, 2024, when the Prior Credit Facility would mature and any outstanding borrowings would become due. The maximum credit amount under the Prior Credit Facility was $5.0 billion.

On May 2, 2022, as part of the Company's spring 2022 redetermination, the borrowing base and elected commitment amount of $1.6 billion was reaffirmed for the Prior Credit Facility.

On October 19, 2022, the Company entered into the Amended & Restated Credit Agreement (the "Credit Agreement" and the senior secured revolving credit facility thereunder, the "Credit Facility") on substantially similar terms as those in the credit agreement governing the Prior Credit Facility. The Credit Agreement, among other things, extended the term to provide for interest-only payments until October 19, 2027 when the Credit Agreement matures and any outstanding borrowings are due, established a borrowing base of $2.0 billion, with an elected commitment amount of $1.5 billion, replaced all provisions and related definitions regarding LIBOR with SOFR, and decreased the maximum leverage ratio from 4.00 to 1.00 to 3.50 to 1.00.

As a result of entering into the Credit Facility, as defined below, the Company recognized a loss on extinguishment of debt of $3.2 million, which was comprised solely of the write-off of certain of the unamortized deferred financing costs associated with the Prior Credit Facility.

As of December 31, 2022, the borrowing base under the Credit Facility was $2.0 billion, with an elected commitment amount of $1.5 billion, and borrowings outstanding of $503.0 million at a weighted-average interest rate of 6.56%, and letters of credit outstanding of $16.4 million.

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 0.75% to 1.75%, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50%, and the SOFR plus 0.1% ("Adjusted SOFR") for a one month period plus 1.00%, or (ii) an Adjusted SOFR plus a margin between 1.75% to 2.75%. 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 of capitalized amounts" in the consolidated statements of operations.

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.

Senior Unsecured Notes

*7.5% Senior Notes***.** On June 24, 2022, the Company issued and sold $600.0 million in aggregate principal amount of 7.5% senior unsecured notes due 2030 (the "7.5% Senior Notes") in a private placement for proceeds of approximately $588.0 million, net of initial purchasers' discounts and commissions. The 7.5% Senior Notes mature on June 15, 2030, and interest is payable semi-annually each June 15 and December 15, commencing on December 15, 2022.

At any time prior to June 15, 2025, the Company may, from time to time, redeem up to 35% of the aggregate principal amount of the 7.5% Senior Notes in an amount of cash not greater than the net cash proceeds from certain equity offerings at the redemption price of 107.5% of the principal amount, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption, if at least 65% of the aggregate principal amount of the 7.5% Senior Notes remains outstanding after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Prior to June 15, 2025, the Company may, at its option, on any one or more occasions, redeem all or a portion of the 7.5% Senior Notes at 100.0% of the principal amount plus an applicable make-whole premium and accrued and unpaid interest. On or after June 15, 2025, the Company may redeem all or a portion of the 7.5% Senior Notes at redemption prices decreasing annually from 103.75% to 100.0% of the principal amount redeemed plus accrued and unpaid interest. Upon the occurrence of certain kinds of change of control that are accompanied by a ratings decline, each holder of the 7.5% Senior Notes may require the Company to repurchase all or a portion of such holder's 7.5% Senior Notes for cash at a price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest.

Redemption of 6.125% Senior Notes and 9.0% Second Lien Notes. On June 24, 2022, the Company used the proceeds from the offering of the 7.5% Senior Notes, along with borrowings under its credit facility, to redeem all of its outstanding 6.125% Senior Notes and 9.0% Second Lien Notes (the "Second Lien Notes"). The Company recognized a loss on extinguishment of debt of approximately $42.4 million in its consolidated statements of operations as a result of the redemptions, which primarily related to redemption premiums and to the write-off of the remaining unamortized premium associated with the 6.125% Senior Notes, partially offset by the write-offs of the remaining unamortized discount associated with the Second Lien Notes and deferred financing costs.

8.0% Senior Notes. On July 6, 2021, the Company issued $650.0 million aggregate principal amount of 8.0% Senior Notes due 2028 (the "8.0% Senior Notes") in a private placement for proceeds of approximately $638.1 million, net of underwriting discounts and commissions and offering costs. The 8.0% Senior Notes mature on August 1, 2028 and have interest payable semi-annually each February 1 and August 1.

At any time prior to August 1, 2024, the Company may, from time to time, redeem up to 35% of the aggregate principal amount of the 8.0% Senior Notes in an amount of cash not greater than the net cash proceeds from certain equity offerings at the redemption price of 108.0% of the principal amount, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption, if at least 65% of the aggregate principal amount of the 8.0% Senior Notes remains outstanding after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Prior to August 1, 2024, the Company may, at its option, on any one or more occasions, redeem all or a portion of the 8.0% Senior Notes at 100.0% of the principal amount plus an applicable make-whole premium and accrued and unpaid interest. On or after August 1, 2024, the Company may redeem all or a portion of the 8.0% Senior Notes at redemption prices decreasing annually from 104.0% to 100.0% of the principal amount redeemed plus accrued and unpaid interest. Upon the occurrence of certain kinds of change of control, the Company must make an offer to repurchase all or a portion of each holder's 8.0% Senior Notes for cash at a price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest.

8.25% Senior Notes. The Company's 8.25% Senior Notes due 2025 (the "8.25% Senior Notes") mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. Since July 15, 2022, the Company may redeem all or a portion of the 8.25% Senior Notes at redemption prices decreasing annually from 102.063% 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. The Company's 6.375% Senior Notes due 2026 (the "6.375% Senior Notes") mature on July 1, 2026 and have interest payable semi-annually each January 1 and July 1. Since July 1, 2022, the Company may redeem all or a portion of the 6.375% Senior Notes at redemption prices decreasing annually from 102.125% 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.

Second Lien Notes

Exchange. On November 5, 2021, the Company closed on its transaction with Chambers Investments, LLC, a private investment vehicle managed by Kimmeridge Energy Management, LLC, to exchange $197.0 million of its outstanding Second Lien Notes for a notional amount of approximately $223.1 million of the Company's common stock. The value of equity to be delivered was based on the optional redemption language in the indenture for the Second Lien Notes. The price of the Company's common stock used to calculate the shares issued was based on the 10-day volume-weighted average price as of August 2, 2021 and equated to 5.5 million shares. As a result of the Second Lien Note Exchange, the Company recognized a loss on the extinguishment of debt of approximately $43.4 million in its consolidated statement of operations for the year ended December 31, 2021, calculated as the notional amount of common stock issued less aggregate principal amount of Second Lien Notes exchanged, net of a pro-rata write-off of associated unamortized discount of $16.9 million and fees incurred.

Covenants

The Company's Credit Facility and the indentures governing the 8.25% Senior Notes, the 6.375% Senior Notes, the 8.0% Senior Notes, and the 7.5% Senior Notes (collectively, the "Senior Unsecured Notes") limit the Company and certain of its subsidiaries with respect to the amount of 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, along with 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: (1) a Leverage Ratio (as defined in the credit agreement governing the Credit Facility) of no more than 3.50 to 1.00 and (2) a Current Ratio (as defined in the credit agreement governing the Credit Facility) of not less than 1.00 to 1.00. The Company was in compliance with these covenants at December 31, 2022.

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, put and call options, and basis differential swaps 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 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.

The Company strives to minimize its credit exposure to any individual counterparty and, as such, the Company had outstanding commodity derivative instruments with eight counterparties as of December 31, 2022. 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.

Contingent Consideration Arrangements

In the second quarter of 2019, the Company completed its divestiture of certain non-core assets in the southern Midland Basin. Additionally, on December 20, 2019, the Company completed the Carrizo Acquisition. Both of these transactions included potential additional contingent consideration if certain specified pricing thresholds were met through the end of 2021. Those pricing thresholds were met for 2021, resulting in a cash receipt and cash payment, respectively, during the first quarter of 2022. Cash received or paid for settlements of contingent consideration arrangements are classified as cash flows from financing activities or cash flows from investing activities, respectively, up to the divestiture or acquisition date fair value, respectively, with any excess classified as cash flows from operating activities. As a result, the Company received $ 20.8 million, of which $8.5 million is presented in cash flows from financing activities with the remaining $12.3 million presented in cash flows from operating activities, and paid $25.0 million, of which $19.2 million is presented in cash flows from investing activities with the remaining $5.8 million presented in cash flows from operating activities. Both of these contingent consideration arrangements were completed as of the end of 2021.

Financial Statement Presentation and Settlements

The Company records its derivative instruments at fair value in the consolidated balance sheets and records changes in fair value, as well as settlements during the period, as “(Gain) loss on derivative contracts” in the consolidated statements of operations. The Company presents the fair value of derivative contracts on a net basis in the consolidated balance sheets as they are subject to master netting arrangements. The following presents the impact of this presentation to the Company’s recognized assets and liabilities for the periods indicated:

	As of December 31, 2022		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
		(In thousands)	
Derivative Assets			
Fair value of derivatives - current	$51,984	($30,652)	$21,332
Other assets, net	$1,343	($889)	$454
Derivative Liabilities			
Fair value of derivatives - current	($46,849)	$30,652	($16,197)
Fair value of derivatives - non current	($14,304)	$889	($13,415)

	As of December 31, 2021		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
		(In thousands)	
Assets			
Commodity derivative instruments	$25,469	($23,921)	$1,548
Contingent consideration arrangements	20,833	—	20,833
Fair value of derivatives - current	**$46,302**	**($23,921)**	**$22,381**
Commodity derivative instruments	$1,119	($869)	$250
Other assets, net	**$1,119**	**($869)**	**$250**
Liabilities			
Commodity derivative instruments (1)	($184,898)	$23,921	($160,977)
Contingent consideration arrangements	(25,000)	—	(25,000)
Fair value of derivatives - current	**($209,898)**	**$23,921**	**($185,977)**
Commodity derivative instruments	($12,278)	$869	($11,409)
Fair value of derivatives - non current	**($12,278)**	**$869**	**($11,409)**

(1) Includes approximately $2.9 million of deferred premiums, which were paid as the applicable contracts settled.

The components of “Loss on derivative contracts” are as follows for the respective periods:

	Years Ended December 31,		
	2022	2021	2020
	(In thousands)		
(Gain) loss on oil derivatives	$287,379	$429,156	($48,031)
Loss on natural gas derivatives	38,803	33,621	14,883
Loss on NGL derivatives	4,771	6,768	2,426
(Gain) loss on contingent consideration arrangements	—	(2,635)	2,976
Loss on September 2020 Warrants liability [1]	—	55,390	55,519
Loss on derivative contracts	**$330,953**	**$522,300**	**$27,773**

(1) A detailed discussion of the Company’s September 2020 Warrants can be found in “Part II, Item 8. Financial Statements and Supplementary Data, Note 7 – Borrowings” of its Annual Report on Form 10-K for the year ended December 31, 2021, which was filed with the SEC on February 24, 2022.

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

	Years Ended December 31,		
	2022	2021	2020
	(In thousands)		
Cash flows from operating activities			
Cash received (paid) on oil derivatives	($429,017)	($350,340)	$98,723
Cash received (paid) on natural gas derivatives	(60,914)	(34,576)	147
Cash paid on NGL derivatives	(3,783)	(10,181)	—
Cash received (paid) for commodity derivative settlements, net	($493,714)	($395,097)	$98,870
Cash received for settlements of contingent consideration arrangements, net	$6,492	$—	$—
Cash flows from investing activities			
Cash paid for settlement of contingent consideration arrangement	($19,171)	$—	($40,000)
Cash flows from financing activities			
Cash received for settlement of contingent consideration arrangement	$8,512	$—	$—

Derivative Positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of December 31, 2022:

Oil Contracts (WTI)	For the Full Year 2023	For the Full Year 2024
Swap Contracts		
Total volume (Bbls)	1,541,500	—
Weighted average price per Bbl	$79.87	$—
Collar Contracts (Three-Way Collars)		
Total volume (Bbls)	1,825,000	—
Weighted average price per Bbl		
Ceiling (short call)	$90.00	$—
Floor (long put)	$70.00	$—
Floor (short put)	$50.00	$—
Collar Contracts (Two-Way Collars)		
Total volume (Bbls)	2,365,000	—
Weighted average price per Bbl		
Ceiling (short call)	$88.26	$—
Floor (long put)	$72.22	$—
Short Call Swaption Contracts (1)		
Total volume (Bbls)	—	1,830,000
Weighted average price per Bbl	$—	$80.30

(1) The 2024 short call swaption contracts have exercise expiration dates of December 29, 2023.

Natural Gas Contracts (Henry Hub)	For the Full Year 2023	For the Full Year 2024
Swap Contracts		
Total volume (MMBtu)	2,140,000	—
Weighted average price per MMBtu	$5.11	$—
Collar Contracts		
Total volume (MMBtu)	8,780,000	—
Weighted average price per MMBtu		
Ceiling (short call)	$6.52	$—
Floor (long put)	$4.37	$—
Natural Gas Contracts (Waha Basis Differential)		
Swap Contracts		
Total volume (MMBtu)	6,080,000	—
Weighted average price per MMBtu	($0.75)	$—
Natural Gas Contracts (HSC Basis Differential)		
Swap Contracts		
Total volume (MMBtu)	7,300,000	7,320,000
Weighted average price per MMBtu	($0.27)	($0.45)

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 for 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. 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, 2022		December 31, 2021	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(In thousands)			
6.125% Senior Notes	$—	$—	$460,241	$455,639
9.0% Second Lien Notes	—	—	319,659	343,633
8.25% Senior Notes	187,238	186,719	187,238	184,429
6.375% Senior Notes	320,783	301,732	320,783	309,556
8.0% Senior Notes	650,000	616,935	650,000	663,000
7.5% Senior Notes	600,000	550,812	—	—
Total	**$1,758,021**	**$1,656,198**	**$1,937,921**	**$1,956,257**

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 sheets. 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 as 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.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021:

	December 31, 2022		
	Level 1	Level 2	Level 3
	(In thousands)		
Commodity derivative assets	$—	$21,786	$—
Commodity derivative liabilities	$—	($29,612)	$—

	December 31, 2021		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets			
Commodity derivative instruments	$—	$1,798	$—
Contingent consideration arrangements	—	20,833	—
Liabilities			
Commodity derivative instruments [1]	—	(172,386)	—
Contingent consideration arrangements	—	(25,000)	—
Total net assets (liabilities)	**$—**	**($174,755)**	**$—**

(1) Includes approximately $2.9 million of deferred premiums which will be paid as the applicable contracts settle.

There were no transfers between any of the fair value levels during any period presented.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Acquisitions. The fair value of assets acquired and liabilities assumed 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 that, 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, 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

2020 Omnibus Incentive Plan

Shares-based awards are granted under 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. At December 31, 2022, there were 1,703,829 shares available for future share-based awards under the 2020 Plan.

RSU Equity Awards

The following table summarizes RSU Equity Award activity for the year ended December 31, 2022:

	RSU Equity Awards (In thousands)	Weighted Average Grant-Date Fair Value per Share
Unvested at the beginning of the year	**968**	**$34.04**
Granted	396	$57.85
Vested	(376)	$35.32
Forfeited	(188)	$35.95
Unvested at the end of the year	**800**	**$44.79**

Grant activity for the years ended December 31, 2022, 2021 and 2020 primarily consisted of RSU Equity Awards granted to executives and employees as part of the annual grant of long-term equity incentive awards with a weighted average grant date fair value of $57.85, $38.59 and $21.07, respectively.

For performance-based RSU Equity Awards granted in 2020 that vested on December 31, 2022, the number of performance-based RSU Equity Awards that could vest was 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. No performance-based RSU Equity Awards were granted during 2022 and 2021.

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	**2022**	**2021**	**2020**
Vesting Multiplier	18 %	50 %	50% - 100%
Target	86,455	28,356	21,920
Vested at end of performance period	15,559	14,177	11,372
Did not vest at end of performance period	70,896	14,179	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 year ended December 31, 2020, the grant date fair value of the performance-based RSU Equity Awards, calculated using a Monte Carlo simulation, was $3.4 million. The following table summarizes the assumptions used and the resulting grant date fair value per performance-based RSU Equity Award granted during the year ended December 31, 2020:

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

The aggregate fair value of RSU Equity Awards that vested during the years ended December 31, 2022, 2021 and 2020 was $22.4 million, $8.7 million and $1.6 million, respectively. As of December 31, 2022, unrecognized compensation costs related to unvested RSU Equity Awards were $ 23.9 million and will be recognized over a weighted average period of 1.9 years.

Cash-Settled Awards

As of December 31, 2022 and 2021, the Company had a total liability of $6.5 million and $15.6 million, respectively, for the outstanding Cash-Settled Awards.

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,		
	2022	**2021**	**2020**
		(In thousands)	
RSU Equity Awards	$15,535	$13,230	$13,030
Cash-Settled Awards	(7,493)	12,627	(4,115)
	8,042	25,857	8,915
Less: amounts capitalized to oil and gas properties	(5,535)	(12,934)	(6,252)
Total share-based compensation expense, net	**$2,507**	**$12,923**	**$2,663**

Note 11 – Stockholders' Equity

Increase in Authorized Common Shares

The Company filed an amendment to its certificate of incorporation, that became effective on May 25, 2022 to increase the number of authorized shares of common stock from 78,750,000 to 130,000,000, as approved by the Company's shareholders at the 2022 Annual Meeting of Shareholders on May 25, 2022.

Second Lien Note Exchange

On November 3, 2021, at a special meeting of shareholders, the Company obtained the requisite shareholder approval for the issuance of approximately 5.5 million shares of the Company's common stock in exchange for an aggregate of $197.0 million principal amount of Second Lien Notes. The exchange was completed on November 5, 2021 and the exchanged Second Lien Notes were immediately cancelled. See "Note 7 – Borrowings" for discussion of the exchange of Second Lien Notes for Company common stock.

Primexx Acquisition

During the fourth quarter of 2021, the Company issued approximately 9.0 million shares of common stock in connection with the Primexx Acquisition, inclusive of the shares of common stock issued to those certain interest owners who exercised their option to sell their interest in the properties included in the Primexx Acquisition. See "Note 4 – Acquisitions and Divestitures" for additional details.

Warrant Exercises

During the year ended December 31, 2021, holders of the September 2020 Warrants and November 2020 Warrants provided notice and exercised all outstanding warrants. As a result of the exercises in 2021, the Company issued a total of 6.9 million shares of its common stock in exchange for 9.0 million outstanding warrants determined on a net shares settlement basis. A detailed discussion of the Company's September 2020 Warrants and November 2020 Warrants can be found in "Part II, Item 8. Financial Statements and Supplementary Data, Note 7 – Borrowings" of its Annual Report on Form 10-K for the year ended December 31, 2021, which was filed with the SEC on February 24, 2022. As of December 31, 2022 and December 31, 2021, no September 2020 or November 2020 Warrants were outstanding.

Note 12 – Income Taxes

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

	Years Ended December 31,		
	2022	2021	2020
		(In thousands)	
Current			
Federal	$2,977	$—	$—
State	4,537	180	3,447
Total current income tax expense	**7,514**	**180**	**3,447**
Deferred			
Federal	—	—	126,903
State	4,279	—	(8,296)
Total deferred income tax expense	**4,279**	**—**	**118,607**
Total income tax expense	**$11,793**	**$180**	**$122,054**

A reconciliation of the income tax expense calculated at the federal statutory rate of21% to income tax expense is as follows:

	Years Ended December 31,		
	2022	2021	2020
		(In thousands)	
Income (loss) before income taxes	$1,221,609	$365,331	($2,411,567)
Income tax expense (benefit) computed at the statutory federal income tax rate	256,538	76,720	(506,429)
State income tax expense (benefit), net of federal benefit	11,393	2,905	(11,827)
Non-deductible expenses related to capital structure transactions	(2,896)	(11,875)	—
Equity based compensation	(1,496)	564	2,746
Other	(1,223)	10,247	(1,621)
Change in valuation allowance	(250,523)	(78,381)	639,185
Income tax expense	**$11,793**	**$180**	**$122,054**

The income tax expense of $11.8 million for the year ended December 31, 2022 is lower than as calculated using the federal statutory rate 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.

As of December 31, 2022 and 2021, the net deferred income tax assets and liabilities are comprised of the following:

	As of December 31,	
	2022	2021
	(In thousands)	
Deferred tax assets		
Oil and natural gas properties	$—	$238,203
Federal net operating loss carryforward	359,784	221,900
Net interest expense limitation	74,628	36,171
Derivative instruments	12,758	30,826
Operating lease right-of-use assets	13,180	8,650
Asset retirement obligations	13,049	12,244
Unvested RSU equity awards	5,391	4,939
Other	11,675	12,892
Total deferred tax assets	$490,465	$565,825
Deferred income tax valuation allowance	(310,281)	(560,804)
Net deferred tax assets	$180,184	$5,021
Deferred tax liability		
Oil and natural gas properties	($174,578)	$—
Operating lease liabilities	(9,885)	(5,021)
Total deferred tax liability	($184,463)	($5,021)
Net deferred tax asset (liability)	**($4,279)**	**$—**

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, 2022, driven primarily by the impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the fourth quarter of 2020. This limits the ability to consider other subjective evidence such as the Company's potential for future growth. Since the second quarter 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 of December 31, 2022, the valuation allowance balance is $310.3 million, reducing the net deferred tax assets tozero.

The Company currently believes it is reasonably possible it could achieve a three-year cumulative level of profitability within the next 12 months, which would enhance its ability to conclude that it is more likely than not that the deferred tax assets would be realized and support a release of substantially all or a portion of the valuation allowance. However, the exact timing and amount of the release is unknown at this time. The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods based on available information each reporting period. 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. The valuation allowance does not preclude the Company from utilizing the tax attributes if it recognizes taxable income.

Inflation Reduction Act

On August 16, 2022, the Inflation Reduction Act (the "IRA") was enacted into law and includes significant changes relating to tax, climate change, energy, and health care. The provisions within the IRA, among other things, include (i) a new 15% corporate alternative minimum tax on corporations with average annual adjusted financial statement income over a three-year period in excess of $1.0 billion, (ii) a new nondeductible 1% excise tax on the value of certain stock that a company repurchases, and (iii) various tax incentives for energy and climate initiatives. Each of these provisions are effective for tax years beginning after December 31, 2022. The Department of the Treasury is expected to publish regulations relevant to many aspects of the IRA. The Company is currently awaiting such guidance and continues to evaluate the effect of the new law to its future cash flows and financial results. The Company does not currently believe this will have a material impact on its cash taxes or income tax expense for the 2023 tax year.

Federal Net Operating Losses ("NOLs") & Interest Limitation Carryforwards

At December 31, 2022, the Company had approximately $1.7 billion of NOLs and a net interest expense carryforward of $355.4 million under Section 163(j) of the Code. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for additional details.

Uncertain Tax Positions

The Company had no significant unrecognized tax benefits at December 31, 2022. 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 2018.

Note 13 – 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. 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, 2022.

	Years Ended December 31,		
	2022	**2021**	**2020**
		(In thousands)	
Components of Lease Costs			
Finance lease costs	$228	$277	$1,489
Amortization of right-of-use assets [(1)]	203	237	1,348
Interest on lease liabilities [(2)]	25	40	141
Operating lease cost [(3)]	38,803	37,734	46,888
Impairment of Operating lease ROU assets [(4)]	—	—	3,575
Short-term lease cost [(5)]	19,426	347	1,821
Variable lease costs [(6)]	2,098	284	259
Total lease costs	**$60,555**	**$38,642**	**$54,032**

(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, 2022, 2021 and 2020, approximately $33.3 million, $23.0 million and $34.2 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 the Company's 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 year ended December 31, 2020 of $3.6 million, which are a component of "Merger, integration and transaction expenses" in the consolidated statements of operations.
(5) Short-term lease cost primarily consists of drilling rigs with contract terms of less than one year.
(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,	
	2022	**2021**
	(In thousands)	
Leases		
Operating leases:		
Operating lease ROU assets	$47,018	$23,884
Current operating lease liabilities	$40,809	$17,599
Long-term operating lease liabilities	21,882	23,547
Total operating lease liabilities	$62,691	$41,146

The table below presents the weighted average remaining lease terms and weighted average discounts rates for the Company's leases as of December 31, 2022.

	December 31, 2022
Weighted Average Remaining Lease Terms (In years)	
Operating leases	3.0
Financing leases	1.2
Weighted Average Discount Rate	
Operating leases	6.2 %
Financing leases	6.6 %

The table below presents the maturity of the Company's lease liabilities as of December 31, 2022.

	Operating Leases	Financing Leases
	(In thousands)	
2023	$43,158	$233
2024	6,815	39
2025	4,366	—
2026	3,805	—
2027	3,846	—
Thereafter	6,488	—
Total lease payments	**68,478**	**272**
Less imputed interest	(5,787)	(12)
Total lease liabilities	**$62,691**	**$260**

Note 14 – Asset Retirement Obligations

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

	Years Ended December 31,	
	2022	2021
	(In thousands)	
Asset retirement obligations, beginning of period	**$56,707**	**$59,090**
Accretion expense	3,997	3,743
Liabilities incurred	669	1,826
Increase due to acquisition of oil and gas properties	—	1,898
Liabilities settled	(2,008)	(1,769)
Dispositions	(4,760)	(7,262)
Revisions to estimates	5,830	(819)
Asset retirement obligations, end of period	**60,435**	**56,707**
Less: Current asset retirement obligations	(6,543)	(2,249)
Non-current asset retirement obligations	**$53,892**	**$54,458**

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, 2022 and 2021 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,	
	2022	2021
	(In thousands)	
Oil and natural gas receivables	$174,107	$171,837
Joint interest receivables	16,778	13,751
Other receivables	48,277	49,053
Total	239,162	234,641
Allowance for credit losses	(2,034)	(2,205)
Total accounts receivable, net	**$237,128**	**$232,436**

Note 16 – Accounts Payable and Accrued Liabilities

	As of December 31,	
	2022	2021
	(In thousands)	
Accounts payable	$191,133	$151,836
Revenues and royalties payable	244,408	294,143
Accrued capital expenditures	58,395	64,412
Accrued interest	42,297	59,600
Total accounts payable and accrued liabilities	**$536,233**	**$569,991**

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, frac service contracts, gathering, processing and transportation service agreements which require minimum volumes of oil, natural gas, or produced water to be delivered and other purchase obligations, as of December 31, 2022.

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
				(In thousands)			
Office space	$5,294	$5,210	$5,364	$9,423	$9,595	$55,966	$90,852
Drilling rig and frac service commitments (1)	251,314	—	—	—	—	—	251,314
Delivery commitments (2)	14,775	26,202	27,264	27,264	22,898	105,848	224,251
Produced water disposal commitments (3)	9,665	8,532	4,509	569	113	—	23,388
Purchase obligations (4)	10,748	8,988	8,988	8,988	8,988	13,017	59,717
Other operating leases	2,095	1,612	408	—	—	—	4,115
Total	**$293,891**	**$50,544**	**$46,533**	**$46,244**	**$41,594**	**$174,831**	**$653,637**

(1) Drilling rig and frac service commitments 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.

(2) 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.

(3) 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.

(4) Purchase obligations represent multi-year energy purchase agreements the Company has entered into to lock in rates for electricity utilized in its operations. Under these contracts, the Company is obligated to purchase a minimum supply of electricity at a fixed price. If the Company does not utilize the minimum amounts of electricity on a monthly basis, the supplier would sell the underutilized quantity at the then market price. The amounts in the table above reflect the aggregate undiscounted financial commitments pursuant to these purchase agreements.

Other Commitments

The following table includes the Company's current oil sales contracts and firm transportation agreements as of December 31, 2022:

Type of Commitment [1]	Region	Start Date	End Date	Committed Volumes (Bbls/d)
Oil sales contract [2]	Permian	January 2023	December 2023	13,750
Oil sales contract [3]	Permian	January 2023	December 2023	8,550
Oil sales contract	Permian	April 2022	March 2023	5,000
Oil sales contract	Permian	February 2022	January 2027	5,000
Oil sales contract	Permian	January 2020	December 2024	10,000
Firm transportation agreement [4][5]	Permian	August 2020	July 2030	10,800
Firm transportation agreement [4]	Permian	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) The committed volumes shown in the table above for this particular oil sales contract are average volumes. For the terms of January 2023-March 2023 and April 2023-December 2023, the committed volumes are 10,000 Bbls/d and 15,000 Bbls/d, respectively.
(3) The committed volumes shown in the table above for this particular oil sales contract are average volumes. For the terms of January 2023-July 2023 and August 2023-December 2023, the committed volumes are 7,500 Bbls/d and 10,000 Bbls/d, respectively.
(4) Each of the firm transportation agreements shown in the table above grant us access to delivery points in several locations along the Gulf Coast. The costs associated with these agreements are recorded to "Gathering, transportation and processing" in the Company's consolidated statements of operations.
(5) 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.

The following table includes the Company's current natural gas firm transportation agreements as of December 31, 2022:

Type of Commitment [1][2]	Region	Start Date	End Date	Committed Volumes (MMBtu/d)
Firm transportation agreement	Permian	October 2023	September 2033	50,000
Firm transportation agreement	Permian	October 2023	September 2033	15,000
Firm transportation agreement	Permian	July 2024	June 2034	10,000

(1) For each of the commitments shown in the table above, the committed MMBtus 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. The costs associated with these agreements are recorded to "Gathering, transportation and processing" in the Company's consolidated statements of operations.

Note 18 – 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. 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 D&M 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 non-producing 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	**2022**	**2021**	**2020**
Oil (MBbls)			
Beginning of period	290,296	289,487	346,361
Extensions and discoveries	41,064	22,520	25,678
Revisions to previous estimates	(31,163)	(10,514)	(49,336)
Purchase of reserves in place	—	35,045	—
Sales of reserves in place	(949)	(24,019)	(9,673)
Production	(23,639)	(22,223)	(23,543)
End of period	**275,609**	**290,296**	**289,487**
Natural Gas (MMcf)			
Beginning of period	577,327	541,598	757,134
Extensions and discoveries	75,801	37,896	44,282
Revisions to previous estimates	(11,155)	(3,389)	(198,628)
Purchase of reserves in place	—	73,445	—
Sale of reserves in place	(7,503)	(34,837)	(20,389)
Production	(41,627)	(37,386)	(40,801)
End of period	**592,843**	**577,327**	**541,598**
NGLs (MBbls)			
Beginning of period	98,104	96,126	67,462
Extensions and discoveries	14,264	7,345	8,349
Revisions to previous estimates	1,376	(3,103)	30,214
Purchase of reserves in place	—	10,366	—
Sale of reserves in place	(1,159)	(6,191)	(3,049)
Production	(7,476)	(6,439)	(6,850)
End of period	**105,109**	**98,104**	**96,126**
Total (MBoe)			
Beginning of period	484,621	475,879	540,012
Extensions and discoveries	67,961	36,180	41,407
Revisions to previous estimates	(31,645)	(14,181)	(52,227)
Purchase of reserves in place	—	57,652	—
Sale of reserves in place	(3,359)	(36,015)	(16,120)
Production	(38,053)	(34,894)	(37,193)
End of period	**479,525**	**484,621**	**475,879**

	Years Ended December 31,		
Proved developed reserves	**2022**	**2021**	**2020**
Oil (MBbls)			
Beginning of period	162,886	128,923	152,687
End of period	170,866	162,886	128,923
Natural gas (MMcf)			
Beginning of period	332,266	238,119	320,676
End of period	351,278	332,266	238,119
NGLs (MBbls)			
Beginning of period	55,720	43,315	24,844
End of period	63,788	55,720	43,315
Total proved developed reserves (MBoe)			
Beginning of period	273,983	211,925	230,977
End of period	293,200	273,983	211,925
Proved undeveloped reserves			
Oil (MBbls)			
Beginning of period	127,410	160,564	193,674
End of period	104,743	127,410	160,564
Natural gas (MMcf)			
Beginning of period	245,061	303,479	436,458
End of period	241,565	245,061	303,479
NGLs (MBbls)			
Beginning of period	42,384	52,811	42,618
End of period	41,321	42,384	52,811
Total proved undeveloped reserves (MBoe)			
Beginning of period	210,638	263,954	309,035
End of period	186,325	210,638	263,954
Total proved reserves			
Oil (MBbls)			
Beginning of period	290,296	289,487	346,361
End of period	275,609	290,296	289,487
Natural gas (MMcf)			
Beginning of period	577,327	541,598	757,134
End of period	592,843	577,327	541,598
NGLs (MBbls)			
Beginning of period	98,104	96,126	67,462
End of period	105,109	98,104	96,126
Total proved reserves (MBoe)			
Beginning of period	484,621	475,879	540,012
End of period	479,525	484,621	475,879

Total Proved Reserves

For the year ended December 31, 2022, the Company's net decrease in proved reserves of5.1 MMBoe was primarily due to the following:

- Increase of 68.0 MMBoe through extensions and discoveries through the Company's development efforts in its operating areas, of which8.7 MMBoe were proved developed reserves;
- Decrease of 31.6 MMBoe for revisions of previous estimates that were primarily comprised of:
    - 44.4 MMBoe reduction due to PUD locations that were reclassified to unproved reserve categories, all of which were in the Permian. Certain PUDs were moved outside of their five-year development window as the Company continues to refine its future development plans for the Permian, including increased application of its "Life of Field" co-development model. This development model focuses on optimization of the value of a reservoir system through concurrent, co-development of multiple target zones within the system utilizing larger scale projects. As a result, the Company believes the model contributes to more consistent capital efficiency of its well inventory over time and its broader Permian development program is now being targeted for larger project sizes, accompanied by longer associated cycle times, based on its testing and delineation efforts during 2022;
    - 13.1 MMBoe reduction primarily due to higher operating costs; offset by
    - 13.7 MMBoe increase primarily due to the change in 12-Month Average Realized Price of crude oil which increased by approximately 45% as compared to December 31, 2021;
    - 12.2 MMBoe increase primarily due to better results than previously forecasted on certain wells turned to production during 2022 in both the Permian and Eagle Ford.
- Decrease of 3.4 MMBoe for sales of reserves in place primarily associated with the divestitures of non-core assets primarily in the Western Delaware Basin; and
- Decrease of 38.1 MMBoe for production.

For the year ended December 31, 2021, the Company's net increase in proved reserves of8.7 MMBoe was primarily due to the following:

- Increase of 36.2 MMBoe through extensions and discoveries through the Company's development efforts in its operating areas, of which10.1 MMBoe were proved developed reserves;
- Decrease of 14.2 MMBoe for revisions of previous estimates that were primarily comprised of:
    - 27.9 MMBoe increase primarily due to the change in 12-Month Average Realized Price of crude oil which increased by approximately 75% as compared to December 31, 2020; offset by
    - 29.0 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 as well as changes in its development plans, primarily due to the Primexx Acquisition, which resulted in PUDs being moved outside of the five-year development window;
    - 13.1 MMBoe reduction due 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.
- Increase of 57.7 MMBoe for purchase of reserves in place associated with the Primexx Acquisition;
- Decrease of 36.0 MMBoe for sales of reserves in place associated with the Western Delaware Basin, Eagle Ford, and Midland non-core asset sales; and
- Decrease of 34.9 MMBoe for production.

For the year ended December 31, 2020, the Company's net decrease in proved reserves of64.1 MMBoe was primarily due to the following:

- Increase of 41.4 MMBoe through extensions and discoveries through the Company's development efforts in its operating areas, of which11.7 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.

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,	
	2022	2021
Oil and natural gas properties:	(In thousands)	
Evaluated properties	$10,367,478	$9,238,823
Unevaluated properties	1,711,306	1,812,827
Total oil and natural gas properties	12,078,784	11,051,650
Accumulated depreciation, depletion, amortization and impairments	(6,343,875)	(5,886,002)
Total oil and natural gas properties, net	**$5,734,909**	**$5,165,648**

Costs Incurred

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

	Years Ended December 31,		
	2022	2021	2020
Acquisition costs:		(In thousands)	
Evaluated properties	$—	$677,250	$—
Unevaluated properties	32,548	301,404	30,696
Development costs	742,991	396,181	379,900
Exploration costs	133,080	137,989	122,865
Total costs incurred	**$908,619**	**$1,512,824**	**$533,461**

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, 2022. 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,		
	2022	2021	2020
Oil ($/Bbl)	$95.02	$65.44	$37.44
Natural gas ($/Mcf)	$5.75	$3.31	$1.02
NGLs ($/Bbl)	$36.40	$29.19	$11.10

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,		
	2022	2021	2020
		(In thousands)	
Future cash inflows	$33,424,190	$23,775,358	$12,458,033
Future costs			
Production	(10,702,897)	(8,038,362)	(5,433,496)
Development and net abandonment	(2,326,789)	(1,927,789)	(2,204,301)
Future net inflows before income taxes	20,394,504	13,809,207	4,820,236
Future income taxes	(3,000,300)	(1,481,005)	(65,405)
Future net cash flows	17,394,204	12,328,202	4,754,831
10% discount factor	(8,390,068)	(6,077,447)	(2,444,441)
Standardized measure of discounted future net cash flows	**$9,004,136**	**$6,250,755**	**$2,310,390**

	Changes in Standardized Measure For the Year Ended December 31,		
	2022	2021	2020
		(In thousands)	
Standardized measure at the beginning of the period	$6,250,755	$2,310,390	$4,951,026
Sales and transfers, net of production costs	(2,208,492)	(1,466,413)	(649,781)
Net change in sales and transfer prices, net of production costs	4,168,425	4,336,078	(2,719,579)
Net change due to purchases of in place reserves	—	797,327	—
Net change due to sales of in place reserves	(36,389)	(105,376)	(202,928)
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	1,338,286	583,976	250,759
Changes in future development cost	(257,344)	(81,480)	361,008
Previously estimated development costs incurred	289,207	209,078	318,470
Revisions of quantity estimates	(215,828)	(104,572)	(671,800)
Accretion of discount	705,127	234,495	536,958
Net change in income taxes	(730,185)	(765,956)	383,999
Changes in production rates, timing and other	(299,426)	303,208	(247,742)
Aggregate change	2,753,381	3,940,365	(2,640,636)
Standardized measure at the end of period	**$9,004,136**	**$6,250,755**	**$2,310,390**

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, 2022.

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.

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. GAAP. 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, 2022 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, 2022.

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, 2022, presented preceding the Company's financial statements included in Part II, Item 8 of this 2022 Annual Report on Form 10-K.

ITEM 9B. Other Information

None.

ITEM 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

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 "2023 Proxy Statement") for our 2023 annual meeting of shareholders. The 2023 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2022.

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.

ITEM 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2023 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2022.

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 2023 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2022.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the 2023 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2022.

ITEM 14. Principal Accountant Fees and Services

The information required by this item is incorporated herein by reference to the 2023 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2022.

PART IV.

ITEM 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this 2022 Annual Report on Form 10-K:

(1) Financial Statements

See index to Financial Statements and Supplementary Data on page 57.

(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits

			Incorporated by reference (File No. 001-14039, unless otherwise indicated)		
Exhibit Number		Description	Form	Exhibit	Filing Date
2.1	(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
2.2		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
2.3		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		Certificate of Amendment to the Certificate of Incorporation of Callon, effective May 14, 2021	8-K	3.1	05/14/2021
3.5		Certificate of Amendment to the Certificate of Incorporation of Callon, effective May 25, 2022	8-K	3.1	05/25/2022
3.6		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		Description of Common Stock	10-K	4.2	02/25/2021
4.3		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
4.4		First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and U.S. Bank National Association, as trustee	8-K	4.4	12/20/2019
4.5		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
4.6		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
4.7		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
4.8		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
4.9		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
4.10		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
4.11		Indenture, dated as of July 6, 2021, by and among the Company, Callon Petroleum Operating Company, Callon (Eagle Ford) LLC, Callon (Niobrara) LLC, Callon (Permian) LLC, Callon (Permian) Minerals LLC, Callon (Utica) LLC, Callon Marcellus Holding, Inc. and U.S. Bank National Association, as trustee	8-K	4.1	07/07/2021
4.12		Registration Rights Agreement among Callon Petroleum Company, Callon Petroleum Operating Company and Primexx Resource Development, LLC, dated October 1, 2021	10-K	4.17	02/24/2022
4.13		Registration Rights Agreement among Callon Petroleum Company, Callon Petroleum Operating Company and BPP Acquisition, LLC, dated October 1, 2021	10-K	4.18	02/24/2022
4.14		Registration Rights Agreement, by and between the Company and Chambers Investment, LLC, dated November 5, 2021	8-K	4.1	11/08/2021

4.15		Indenture, dated as of June 24, 2022, by and among Callon Petrol eum Company, Callon Petroleum Operating Company, Callon (Permian) LLC, Callon (Eagle Ford) LLC, Callon (Permian) Minerals LLC, Callon (Niobrara) LLC, Callon (Utica) LLC and Callon Marcellus Holding, Inc. and U.S. Bank Trust Company, National Association, as trustee	8-K	4.1	06/24/2022
10.1	(d)	Amended & Restated Credit Agreement, dated as of October 19, 2022, by and among the Company, JPMorgan Chase Bank, N.A., as administrative agent for the lenders party thereto, and the other lenders party thereto	8-K	10.1	10/24/2022
10.2	(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
10.3	(b)	Amended and Restated 2018 Omnibus Incentive Plan	10-K	10.7	02/27/2020
10.4	(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
10.5	(b)	Form of Callon Petroleum Company 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
10.6	(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
10.7	(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
10.8	(b)	Callon Petroleum Company 2020 Omnibus Incentive Plan	DEF 14A	B	04/28/2020
10.9	(b)	First Amendment to Callon Petroleum Company 2020 Omnibus Incentive Plan	8-K	10.5	04/16/2021
10.10	(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
10.11	(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
10.12	(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
10.13	(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
10.14	(b)	Deferred Compensation Plan for Outside Directors, as Amended and Restated as of January 1, 2021	10-K	10.29	02/25/2021
10.15	(b)	Form of Callon Petroleum Company Restricted Stock Unit Award Agreement, adopted on March 12, 2021 under the 2020 Omnibus Incentive Plan	8-K	10.1	04/16/2021
10.16	(b)	Form of Callon Petroleum Company Cash Performance Unit Award Agreement, adopted on March 12, 2021 under the 2020 Omnibus Incentive Plan	8-K	10.2	04/16/2021
10.17	(b)	Form of Amendment, adopted on September 21, 2022, to Callon Petroleum Company Cash Performance Unit Award Agreement, originally adopted on March 12, 2021 under the 2020 Omnibus Incentive Plan	10-Q	10.3	11/03/2022
10.18	(b)	Form of Callon Petroleum Company Returns Program Cash Incentive Award Agreement, adopted on March 9, 2022 under the 2020 Omnibus Incentive Plan	10-Q	10.1	05/05/2022
10.19	(b)	Form of Amendment, adopted on September 21, 2022, to Callon Petroleum Company Returns Program Cash Incentive Award Agreement, originally adopted on March 9, 2022 under the 2020 Omnibus Incentive Plan	10-Q	10.4	11/03/2022
10.20	(b)	Form of Callon Petroleum Company Business Sustainability Cash Incentive Award Agreement, adopted on March 9, 2022 under the 2020 Omnibus Incentive Plan	10-Q	10.2	05/05/2022
10.21	(b)	Form of Amendment, adopted on September 21, 2022, to Callon Petroleum Company Business Sustainability Cash Incentive Award Agreement, originally adopted on March 9, 2022 under the 2020 Omnibus Incentive Plan	10-Q	10.5	11/03/2022
10.22	(b)	Callon Petroleum Company Executive Severance Pay Plan	10-Q	10.1	11/03/2022
10.23	(b)	Callon Executive Change in Control Severance Compensation Plan	10-Q	10.2	11/03/2022
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, 2022			
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/ Kevin Haggard	Date:	February 23, 2023
By: Kevin Haggard 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.	Date:	February 23, 2023
Joseph C. Gatto, Jr. (principal executive officer)		
/s/ Kevin Haggard	Date:	February 23, 2023
Kevin Haggard (principal financial officer)		
/s/ Gregory F. Conaway	Date:	February 23, 2023
Gregory F. Conaway (principal accounting officer)		
/s/ L. Richard Flury	Date:	February 23, 2023
L. Richard Flury (chairman of the board of directors)		
/s/ Frances Aldrich Sevilla-Sacasa	Date:	February 23, 2023
Frances Aldrich Sevilla-Sacasa (director)		
/s/ Matthew R. Bob	Date:	February 23, 2023
Matthew R. Bob (director)		
/s/ Barbara J. Faulkenberry	Date:	February 23, 2023
Barbara J. Faulkenberry (director)		
/s/ Anthony J. Nocchiero	Date:	February 23, 2023
Anthony J. Nocchiero (director)		
/s/ Mary Shafer-Malicki	Date:	February 23, 2023
Mary Shafer-Malicki (director)		
/s/ James M. Trimble	Date:	February 23, 2023
James M. Trimble (director)		
/s/ Steven A. Webster	Date:	February 23, 2023
Steven A. Webster (director)		

Exhibit 21.1

Subsidiaries of Callon Petroleum Company

Name	State of Incorporation
Callon Petroleum Operating Company	Delaware
Callon (Permian) LLC	Delaware
Callon (Eagle Ford) LLC	Delaware

Exhibit 22.1

Subsidiary Guarantors of Callon Petroleum Company

Name	State of Incorporation
Callon Petroleum Operating Company	Delaware
Callon (Permian) LLC	Delaware
Callon (Eagle Ford) LLC	Delaware
Callon (Permian) Minerals LLC	Delaware
Callon (Niobrara) LLC	Delaware
Callon (Utica) LLC	Delaware
Callon Marcellus Holding Inc.	Delaware
Callon (Marcellus) LLC	Delaware

Each of the above subsidiaries of Callon Petroleum Company has fully guaranteed on a senior unsecured, joint and several basis each of the debt securities of the Company listed below:

Debt Securities of the Company Guaranteed by each of the Subsidiary Guarantors.

8.25% Senior Notes due July 15, 2025
6.375% Senior Notes due July 1, 2026
8.0% Senior Notes due August 1, 2028
7.5% Senior Notes due June 15, 2030

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 23, 2023, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Callon Petroleum Company on Form 10-K for the year ended December 31, 2022. We consent to the incorporation by reference of said reports in the Registration Statements of Callon Petroleum Company on Forms S-3ASR (File No. 333-230748, File No. 333-235634, and File No. 333-261235), on Form S-3 (File No. 333-251490) and on Forms S-8 (File No. 333-109744, File No. 333-176061, File No. 333-188008, File No. 333-212044, File No. 333-224829, File No. 333-235635, File No. 333-235636, and File No. 333-239006).

/s/ GRANT THORNTON LLP

Houston, Texas
February 23, 2023

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 23, 2023

Callon Petroleum Company
2000 W. Sam Houston Parkway S.
Suite 2000
Houston, Texas 77042

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to the references to us and to our reserves reports for the years ended December 31, 2020, December 31, 2021, and December 31, 2022, in Callon Petroleum Company's Annual Report on Form 10-K for the year ended December 31, 2022, to the references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to the references to our report of third party dated February 9, 2023, containing our opinion on the proved reserves, as of December 31, 2022, attributable to certain properties in which Callon Petroleum Company has represented it holds an interest (our Report), and to the inclusion of our Report as an exhibit in Callon Petroleum Company's Annual Report on Form 10-K for the year ended December 31, 2022. We also consent to all such references and to the incorporation by reference of our Report in the Registration Statements to be filed by Callon Petroleum Company on its Form S-3 (File No. 333-251490), Form S-3ASR (File No. 333-230748, File No. 333-235634, and File No. 333-261235), and Form S-8 (File No. 333-109744, File No. 333-176061, File No. 333-188008, File No. 333-212044, File No. 333-224829, File No. 333-235635, File No. 333-235636, and File No. 333-239006).

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATIONS

I, Joseph C. Gatto, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Joseph C. Gatto, Jr.
Joseph C. Gatto, Jr.
President and Chief Executive Officer
(Principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Kevin Haggard, certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Kevin Haggard

Kevin Haggard
Senior Vice President & Chief Financial Officer
(Principal financial officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Annual Report on Form 10-K of Callon Petroleum Company for the year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacities and on the dates indicated below, each hereby certify pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Report fully complies with requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	February 23, 2023	/s/ Joseph C. Gatto, Jr.
		Joseph C. Gatto, Jr.
		(Principal executive officer)
Date:	February 23, 2023	/s/ Kevin Haggard
		Kevin Haggard
		(Principal financial officer)

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 9, 2023

Callon Petroleum Company
2000 W. Sam Houston Parkway South
Suite 2000
Houston, Texas 77042

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2022, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Callon Petroleum Company (Callon) has represented it holds an interest. This evaluation was completed on February 9, 2023. The properties evaluated herein consist of working interests located in Texas. Callon has represented that these properties account for 100 percent on a net equivalent barrel basis of Callon's net proved reserves as of December 31, 2022. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Callon.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2022. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Callon after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Callon to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Callon, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at the nominal discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Callon and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Callon with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

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

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

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) 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.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for 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, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Callon, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Callon.

Callon has represented that its senior management is committed to the development plan provided by Callon and that Callon has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics,

(2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Callon from wells drilled through December 31, 2022, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of daily and monthly production data available for certain properties only through November 2022. Estimated cumulative production, as of December 31, 2022, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Callon, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Callon. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, NGL Prices

Callon has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Callon supplied differentials to a West Texas Intermediate (WTI) reference price of $93.67 per barrel and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $95.02 per barrel of oil and condensate and $36.40 per barrel of NGL.

Gas Prices

Callon has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Callon supplied differentials to the Henry Hub reference price of $6.36 per million Btu and the prices were held constant thereafter. Btu factors provided by Callon were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $5.751 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes and ad valorem taxes were calculated using rates provided by Callon based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses and future capital expenditures, provided by Callon and based on existing economic conditions, were held constant for the lives of the properties. Certain operating expenses and abandonment costs for the developed and undeveloped properties were provided by Callon at the asset level. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Callon for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

<u>Summary of Conclusions</u>

DeGolyer and MacNaughton has performed an independent evaluation of the extent and value of the estimated net proved oil, condensate, NGL, and gas reserves of certain properties in which Callon has represented it holds an interest. The estimated net proved reserves, as of December 31, 2022, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2022			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	170,866	63,788	351,278	293,200
Proved Undeveloped	104,743	41,321	241,565	186,325
Total Proved	**275,609**	**105,109**	**592,843**	**479,525**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2022, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	**Total Proved (M$)**
Future Gross Revenue	20,610,474	33,424,191
Production and Ad Valorem Taxes	1,177,617	1,871,178
Operating Expenses	6,289,122	8,831,717
Capital and Abandonment Costs	136,657	2,326,789
Future Net Revenue	13,007,078	20,394,506
Present Worth at 10 Percent	7,122,919	10,534,834

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant’s ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2022, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Callon. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Callon. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

/s/ Dilhan Ilk

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am an Executive Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Callon Petroleum Company dated Febraury 9, 2023, and that I, as Executive Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 12 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton