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

FORM 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2021

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 001-35049

EARTHSTONE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**84-0592823**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1400 Woodloch Forest Drive, Suite 300
The Woodlands, Texas 77380
(Address of principal executive offices)
Registrant's telephone number, including area code: (281) 298-4246

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Class A Common Stock, $0.001 par value per share	ESTE	New York Stock Exchange (NYSE)

Securities registered under 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 15(d) of the Exchange 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 the 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 and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to post such files). Yes ☑ No ☐

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

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

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

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price of $11.07 per share at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was approximately $263,687,345.

As of March 3, 2022, 73,301,255 shares of the registrant's Class A Common Stock and 34,302,535 shares of Class B Common Stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for its 2022 Annual Meeting of Stockholders (the "Proxy Statement"), are incorporated by reference into Part III of this Annual Report on Form 10-K.

TABLE OF CONTENTS

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts contained in this report are forward-looking statements. These forward-looking statements can generally be identified by the use of words such as "may," "will," "could," "should," "project," "intends," "plans," "pursue," "target," "continue," "believes," "anticipates," "expects," "estimates," "guidance," "possible," "probable," "predicts," or "potential," the negative of such terms or variations thereon, or other comparable terminology. Statements that describe our future plans, strategies, intentions, expectations, objectives, goals, potential acquisitions or mergers or prospects are also forward-looking statements. Actual results could differ materially from those anticipated in this filing or these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- continued volatility in commodity prices for oil, natural gas and natural gas liquids and the effect of prices set or influenced by action of the Organization of Petroleum Exporting Countries ("OPEC"), its members and other oil and natural gas producing countries;
- the effect of existing and future laws, governmental regulations and the political and economic climates of the United States particularly with respect to climate change, alternative energy and similar topical movements;
- substantial changes in estimates of our proved reserves;
- substantial declines in the estimated values of our proved oil and natural gas reserves;
- our ability to replace our oil and natural gas reserves;
- impacts of world health events, including the coronavirus ("COVID-19") pandemic;
- the risk of the actual presence or recoverability of oil and natural gas reserves and that future production rates may be less than estimated;
- the potential for production decline rates and associated production costs for our wells to be greater than we forecast;
- the timing and extent of our success in acquiring, discovering, developing and producing oil and natural gas reserves;
- the financial ability and willingness of our partners under our joint operating agreements to join in our plans for future exploration, development and production activities;
- our ability to acquire additional mineral leases;
- the cost and availability of high-quality equipment and services with fully trained and adequate personnel, such as contract drilling rigs and completion equipment on a timely basis and at reasonable prices;
- risks in connection with potential acquisitions and the integration of significant acquisitions or assets acquired through merger or otherwise;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits;
- the possibility that potential divestitures may not occur or could be burdened with unforeseen costs;
- unanticipated reductions in the borrowing base under the credit agreement we are party to;
- risks incidental to the drilling and operation of oil and natural gas wells including mechanical failures;
- our dependence on the availability, use and disposal of water in our drilling, completion and production operations;
- the availability of sufficient pipeline and other transportation facilities to carry our production to market and the impact of these facilities on realized prices;
- significant competition for oil and natural gas acreage and acquisitions;
- our ability to retain key members of senior management and key technical and financial employees;
- changes in environmental laws and the regulation and enforcement related to those laws;

- the identification of and severity of adverse environmental events and governmental responses to these or other environmental events;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulations, derivatives reform, and changes in federal and state income taxes;
- future ESG compliance developments and increased attention to such matters which could adversely affect our ability to raise equity and debt capital;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we conduct business, may be less favorable than expected, including the possibility that economic conditions in the United States could deteriorate and that capital markets for equity and debt could be disrupted or unavailable;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States and acts of terrorism or sabotage;
- our insurance coverage may not adequately cover all losses that may be sustained in connection with our business activities;
- other economic, competitive, governmental, regulatory, legislative, including federal and state regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- the effect of our oil and natural gas derivative activities;
- title to the properties in which we have an interest may be impaired by title defects;
- our dependency on the skill, ability and decisions of third-party operators of oil and natural gas properties in which we have non-operated working interests; and
- possible adverse results from litigation and the use of financial resources to defend ourselves.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this report. Other than as required under the applicable securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise. You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made.

For further information regarding these and other factors, risks and uncertainties affecting us, see Part I, Item 1A. Risk Factors of this report.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and within this report.

3-D seismic – An advanced technology method of detecting accumulation of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Bbl – One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf – One billion cubic feet of natural gas.

Boe – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent. The ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.

Btu **–** British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one-degree Fahrenheit.

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

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following exploration including the drilling and completion of additional wells and the installation of production facilities.

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.

Dry hole or ***well*** **–** A well found to be incapable of producing hydrocarbons economically.

ESG – Environmental, Social and Governance.

Exploitation – A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well **–** A well drilled to find and produce oil or natural gas reserves in an area or a potential reservoir not classified as proved.

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

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

Horizontal drilling – A drilling technique that permits the operator to drill horizontally within a specified targeted reservoir and thus exposes a larger portion of the producing horizon to a wellbore than would otherwise be exposed through conventional vertical drilling techniques.

Hydraulic fracture or ***Frac*** – A well stimulation method by which fluid, comprised largely of water and proppant (purposely sized particles used to hold open an induced fracture) is injected downhole and into the producing formation at high pressures and rates in order to exceed the rock strength and create a fracture such that the proppant material can be placed into the fracture to enhance the productive capability of the formation.

Injection well – A well which is used to inject gas, water, or liquefied petroleum gas under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

Joint Operating Agreement or ***JOA*** – Any agreement between working interest owners concerning the duties and responsibilities of the operator and rights and obligations of the non-operators.

MBbls **–** One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe **–** One thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBoe – One million barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBtu – One million Btu.

Mcf – One thousand cubic feet.

MMcf – One million cubic feet.

Net acres or ***net wells*** – The sum of the fractional working interests owned in gross acres or gross wells.

NGLs – Natural gas liquids measured in barrels. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics.

NYMEX – The New York Mercantile Exchange.

Plugging and abandonment or ***P&A*** – Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

PV-10 – The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with the SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (ii) depreciation, depletion and amortization.

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

Proppant – A solid material, typically treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment.

Proved developed nonproducing reserves or ***PDNP*** – Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending completion activities and the installation of surface equipment or gathering facilities or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but nonproducing reserves.

Proved developed producing reserves or ***PDP*** – Reserves that can be expected to be recovered from existing wells and completions with existing equipment and operating methods.

Proved developed reserves or ***PD*** – The estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved reserves – Those quantities of oil and natural 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.

Proved undeveloped reserves or ***PUD*** – 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.

Recompletion – The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Re-engineering – A process involving a comprehensive review of the mechanical conditions associated with wells and equipment in producing fields. Our re-engineering practices typically result in a capital expenditure plan which is implemented over time to workover (see below) and re-complete wells and modify down hole artificial lift equipment and surface equipment and facilities. The programs are designed specifically for individual fields to increase and maintain production, reduce down-time and mechanical failures, lower per-unit operating expenses, and therefore, improve field economics.

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

Royalty interest – An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SEC – United States Securities and Exchange Commission.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time the reserve was estimated but were not producing due to market conditions, mechanical difficulties or because production equipment or pipelines were not yet installed. These reserves are included in the PDNP category in our reserve report.

Standardized Measure – The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

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

Working interest or **WI** – The ownership interest, generally defined in a JOA, that gives the owner the right to drill, produce and/or conduct operating activities on the property and share in the sale of production, subject to all royalties, overriding royalties and other burdens and obligates the owner of the interest to share in all costs of exploration, development operations and all risks in connection therewith.

Workover – Operations on a producing well to restore or increase production.

WTI – West Texas Intermediate light sweet crude oil, a benchmark in crude oil pricing.

PART I

Item 1. Business

Overview

Earthstone Energy, Inc., a Delaware corporation ("Earthstone" and together with our consolidated subsidiaries, the "Company," "our," "we," "us," or similar terms), is a growth-oriented independent oil and gas company engaged in the acquisition and development of oil and gas reserves through activities that include drilling and development of undeveloped leases, as well as asset and corporate acquisitions and mergers. Our operations are all in the upstream segment of the oil and natural gas industry and all our properties are onshore in the United States. Our assets are currently located in the Midland Basin in West Texas, the Eagle Ford Trend in South Texas and the Delaware Basin in New Mexico.

2021 Highlights

The following are highlights of our 2021 activities:

- Signed Purchase and Sale Agreement on the Chisholm Acquisition on December 15, 2021 which was closed on February 15, 2022
- Closed the Foreland Acquisition and the BCC Acquisition on November 2, 2021
- Closed the Tracker Acquisition and the Sequel Acquisition on July 20, 2021
- Closed the Eagle Ford Acquisitions during the second quarter of 2021
- Closed the IRM Acquisition on January 7, 2021
- Full year 2021 average daily sales volumes of 24,809 Boepd exceeded our production goals and increased 62% over 2020
- Maintained strong balance sheet and liquidity position with $330.0 million of undrawn capacity on a $650.0 million senior revolving credit facility and a cash balance of $4.0 million as of December 31, 2021
- Continued development of our properties which included drilling 29 gross / 25.4 net operated wells and completing 19 gross / 15.4 net operated wells

We spent a total of approximately $280.4 million, net of customary purchase price adjustments, and issued 21,530,705 shares of our Class A common stock with an acquisition date fair value of $166.5 million, related to the four acquisitions that were closed during 2021. In the aggregate, these acquisitions added significant scale by increasing our proved reserves by 60.0 MMBoe, increasing sales volumes by 3.4 MMBoe and expanding our Permian Basin acreage footprint by approximately 199% gross / 266% net.

Recent Developments

Bighorn Agreement

On January 30, 2022, Earthstone, Earthstone Energy Holdings, LLC, a subsidiary of Earthstone ("EEH"), and Bighorn Asset Company, LLC, a Delaware limited liability company ("Bighorn"), as seller, entered into a Purchase and Sale Agreement (the "Bighorn Agreement") that was previously reported on Form 8-K filed with the SEC on February 2, 2022. Pursuant to the Bighorn Agreement, EEH will acquire (the "Bighorn Acquisition") interests in oil and gas leases and related property of Bighorn located in the Midland Basin in West Texas, for a purchase price (the "Bighorn Purchase Price") of $770 million in cash and 6,808,511 shares of Class A common stock, $0.001 par value per share of Earthstone (the "Class A Common Stock"). The Bighorn Purchase Price is subject to customary purchase price adjustments with an effective date of January 1, 2022. In connection with the Bighorn Agreement, EEH deposited $50 million in cash into a third-party escrow account as a deposit pursuant to the Bighorn Agreement, which will be credited against the Bighorn Purchase Price upon closing of the Bighorn Acquisition. The Bighorn Acquisition is expected to close in the second quarter of 2022.

Credit Agreement

On January 30, 2022, Earthstone, EEH, as Borrower, Wells Fargo Bank, National Association ("Wells Fargo") as Administrative Agent, the lenders party thereto (the "Lenders") and the guarantors party thereto entered into an amended and restated Fifth Amendment (the "Amendment") to the Credit Agreement dated November 21, 2019, by and among EEH, as Borrower, Earthstone, as Parent, Wells Fargo, as Administrative Agent and Issuing Bank, Royal Bank of Canada, as Syndication Agent, Truist Bank, Citizens Bank, N.A., KeyBank National Association, U.S. Bank National Association, Fifth

Third Bank, PNC Bank, National Association, and Bank of America, N.A., as Documentation Agents, and the Lenders party thereto (together with all amendments or other modifications, the "Credit Agreement"). Among other things, the Amendment increased the borrowing base and corresponding elected commitments from $650 million to $825 million upon the closing ("Chisholm Closing") of that certain Purchase and Sale Agreement dated as December 15, 2021 (the "Chisholm Agreement") by and among Earthstone, EEH, Chisholm Energy Operating, LLC ("OpCo") and Chisholm Energy Agent, Inc. ("Agent" and collectively with OpCo, "Chisholm"); provides that upon the closing of the Bighorn Acquisition, the borrowing base and corresponding elected commitments would increase to $1.325 billion, unless Earthstone completes an unsecured senior notes offering ("Notes Offering") prior to the closing of the Bighorn Acquisition in which case the elected commitments will be reduced by the amount of the net proceeds from a Notes Offering up to $500 million; provides for an increase in interest rates by 0.50% in the event a Notes Offering has not been completed prior to the closing of the Bighorn Acquisition; provides mechanics relating to the transition from LIBOR to a benchmark replacement rate, the Secured Overnight Financing Rate ("SOFR"), to be effective contemporaneously with the effectiveness of the Amendment on January 30, 2022; adds certain hedging requirements relating to anticipated oil and natural gas production of the properties to be acquired pursuant to the Bighorn Acquisition; adjusts some financial covenants; redefines the limitations on certain restricted payments the Borrower may make; and made certain administrative changes to the Credit Agreement.

Securities Purchase Agreement

As previously reported on Form 8-K filed with the SEC on February 2, 2022, on January 30, 2022 Earthstone entered into a securities purchase agreement (the "Securities Purchase Agreement") with EnCap Capital Energy Fund XI, L.P. ("EnCap Fund XI"), an affiliate of EnCap Investments L.P. ("EnCap"), and Cypress Investments, LLC, a fund managed by Post Oak Energy Capital, LP ("Post Oak" and collectively with EnCap Fund XI, the "Investors") to sell, in a private placement (the "Private Placement"), 280,000 shares of newly authorized Series A convertible preferred stock, $0.001 par value per share of Earthstone (the "Preferred Stock"), each share of which will be convertible into 90.0900900900901 shares of Class A Common Stock for anticipated gross proceeds of $280.0 million, at a price of $1,000.00 per share of Preferred Stock (or $11.10 per share of Class A Common Stock on an as-converted basis). The Private Placement is contingent upon the closing of the Bighorn Acquisition. The Company intends to use the net proceeds from the sale of the Preferred Stock to partially fund the Bighorn Acquisition. The Preferred Stock will convert automatically on the 20th calendar day after Earthstone mails a definitive information statement to holders of its Class A Common Stock and Class B common stock, $0.001 par value per share of Earthstone ("Class B Common Stock" and collectively, with the Class A Common Stock, the "Common Stock") notifying them that holders of a majority of the outstanding shares of Common Stock have consented to the conversion feature of the Preferred Stock and the issuance of Class A Common Stock upon conversion of the Preferred Stock. As of January 30, 2022, Earthstone had received written consent for the conversion feature of the Preferred Stock and the issuance of the Class A Common Stock issuable upon conversion of the Preferred Stock from stockholders representing more than 50% of Earthstone's outstanding shares of Common Stock. As of the date of the Securities Purchase Agreement, EnCap and its affiliates beneficially owned approximately 46.5% of the outstanding voting power of Earthstone. Two members of the board of directors of Earthstone (the "Board") are employed by EnCap. The Securities Purchase Agreement and the Private Placement were evaluated and unanimously approved by the audit committee (the "Audit Committee") of the Board and unanimously approved by the Board.

Chisholm Acquisition

On February 15, 2022, Earthstone, EEH, Chisholm, as seller, consummated the transactions contemplated in the Chisholm Agreement that was previously reported on Form 8-K filed with the SEC on December 17, 2021. At the closing of the Chisholm Agreement, among other things, EEH acquired (the "Chisholm Acquisition") interests in oil and gas leases and related property of Chisholm located in Lea County and Eddy County, New Mexico, for aggregate consideration consisting of: (i) approximately $314.7 million in cash, net of preliminary and customary purchase price adjustments and remains subject to post-closing settlement between EEH and Chisholm paid at the closing of the Chisholm Acquisition, (ii) $70 million in cash to be paid as follows: $40 million to be paid six months after the closing of the Chisholm Acquisition and $30 million to be paid 12 months after the closing of the Chisholm Acquisition, subject to acceleration in the event that Earthstone receives gross proceeds of more than $450 million from a high yield bond offering or more than $50 million in gross proceeds from an offering of Class A Common Stock or preferred stock; and (iii) 19,417,476 shares of Class A Common Stock. See further discussion in *Note 14. Related Party Transactions* and *Note 19. Subsequent Events* in the *Notes to Consolidated Financial Statements*.

Cash consideration for the Chisholm Acquisition was funded by borrowings under our senior secured revolving credit facility whose borrowing base was increased from $650 million to $825 million upon consummation of the Chisholm Acquisition.

Foreland-BCC Acquisition

On November 2, 2021, Earthstone, EEH and Foreland Investments LP, a Delaware limited partnership ("Foreland"), consummated the transactions contemplated in the Purchase and Sale Agreement dated as of September 30, 2021 by and among

Earthstone, EEH and Foreland (the “Foreland Purchase Agreement”) that was previously reported on Form 8-K filed with the SEC on October 4, 2021. At the closing of the Foreland Purchase Agreement, EEH acquired (the “Foreland Acquisition”) interests in oil and gas leases and related property of Foreland located in Irion County and Crockett County, Texas, for a purchase price consisting of: (i) $16.3 million in cash, and (ii) 2,611,111 shares of Class A Common Stock.

Also, on November 2, 2021, Earthstone, EEH and BCC-Foreland LLC, a Delaware limited liability company (“BCC”), consummated the transactions contemplated in the Purchase and Sale Agreement dated as of September 30, 2021 by and among Earthstone, EEH and BCC (the “BCC Purchase Agreement”) that was previously reported on Form 8-K filed with the SEC on October 4, 2021. At the closing of the BCC Purchase Agreement, EEH acquired (the “BCC Acquisition” and with the Foreland Acquisition, the “Foreland-BCC Acquisition”) certain well-bore interests and related equipment held by BCC that were part of a joint development agreement between Foreland, Foreland Operating, LLC, and BCC involving portions of the acreage covered by the Foreland Purchase Agreement for a purchase price of $23.0 million in cash. See further discussion in *Note 3. Acquisitions and Divestitures* in the *Notes to Consolidated Financial Statements*.

Tracker/Sequel Acquisitions

On July 20, 2021, Earthstone, EEH, Tracker Resource Development III, LLC (“Tracker OpCo”), and TRD III Royalty Holdings (TX), LP (“RoyaltyCo” and collectively with Tracker OpCo, the “Tracker”) consummated the transactions contemplated in the Purchase and Sale Agreement dated March 31, 2021 by and among Earthstone, EEH and Seller (the “Tracker Agreement”) that was previously reported on Form 8-K filed with the SEC on April 5, 2021. At the closing of the Tracker Agreement, EEH acquired (the “Tracker Acquisition”) interests in oil and gas leases and related property of Tracker located in Irion County, Texas (the “Tracker Assets”) for aggregate consideration consisting of: (i) $18.8 million in cash, and (ii) 4.7 million shares of Class A Common Stock.

Also, on July 20, 2021, Earthstone, EEH, SEG-TRD LLC, a Delaware limited liability company (“SEG-I”), and SEG-TRD II LLC, a Delaware limited liability company (“SEG-II” and collectively with SEG-I, “Sequel”), consummated the transactions contemplated in the Purchase and Sale Agreement dated March 31, 2021 by and among Earthstone, EEH and Sequel that was previously reported on Form 8-K filed with the SEC on April 5, 2021. At the closing of the Sequel Agreement, EEH acquired (the “Sequel Acquisition”) certain well-bore interests and related equipment held by Sequel that were part of a joint development agreement between Tracker and Sequel involving portions of the acreage covered by the Tracker Agreement for aggregate consideration consisting of: (i) $41.4 million in cash, and (ii) 1.5 million shares of Class A Common Stock. See further discussion in *Note 3. Acquisitions and Divestitures* and *Note 14. Related Party Transactions* in the *Notes to Consolidated Financial Statements*.

Cash consideration for the Tracker Acquisition and the Sequel Acquisition was funded by borrowings under our senior secured revolving credit facility whose borrowing base was increased from $475 million to $550 million on July 20, 2021.

Eagle Ford Acquisitions

During the second quarter of 2021, we acquired working interests in certain assets we operate in southern Gonzales County, Texas (the “Eagle Ford Acquisitions”) from four separate sellers for approximately $45.2 million in cash. We funded the Eagle Ford Acquisitions with cash on hand and borrowings under our senior secured revolving credit facility. The effective date of the Eagle Ford Acquisitions was April 1, 2021. One of the four sellers was a related party entity. See further discussion in *Note 3. Acquisitions and Divestitures* and *Note 14. Related Party Transactions* in the *Notes to Consolidated Financial Statements*.

IRM Acquisition

On January 7, 2021, Earthstone, EEH, Independence Resources Holdings, LLC (“Independence”), and Independence Resources Manager, LLC (“Independence Manager” and collectively with Independence, the “Seller”) consummated the transactions contemplated in the Purchase and Sale Agreement dated December 17, 2020 (the “IRM Purchase Agreement”) that was previously reported on Form 8-K filed with the SEC on December 22, 2020. At the closing of the IRM Purchase Agreement, EEH acquired (the “IRM Acquisition”) all of the issued and outstanding limited liability company interests in certain wholly owned subsidiaries of Independence and Independence Manager for aggregate consideration consisting of: (i) cash of approximately $140.5 million and (ii) 12,719,594 shares of Class A Common Stock.

Our Properties

As operator, across the majority of our acreage in the Midland and Delaware Basins, we manage and are able to directly influence development and production of our operated properties. Independent contractors engaged by us provide all the equipment and personnel associated with drilling and completion activities. We employ petroleum engineers, geologists and land professionals who work on improving drilling and completion processes, operating costs, production rates and reserves. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price and cost fluctuations. Our status as an operator has allowed us to pursue the development of undeveloped acreage, further develop existing properties and generate new projects.

As is common in our industry, we selectively participate in drilling and developmental activities in non-operated properties. Decisions to participate in non-operated properties are dependent upon the technical and economic nature of the projects and the operating expertise and financial standing of the operators.

As of December 31, 2021, our estimated proved oil and natural gas reserves were approximately 147,587 MBoe based on the reserve report prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"), our independent petroleum engineers. Based on this report, at December 31, 2021, our estimated proved reserve quantities were approximately 41% oil, 32% natural gas and 26% NGLs with 63% of those reserves classified as proved developed.

As a result of the Chisholm Acquisition, we added an estimated 54.3 MBoe of proved reserves which were approximately 64% oil, 19% natural gas and 17% NGLs.

Midland Basin

As of December 31, 2021, we had approximately 102,100 net acres in the core of the Midland Basin that are highly contiguous on a project-by-project basis which allow us to drill multi-well pads. Of this acreage, 94% is operated and 6% is non-operated. We hold an approximate 96% working interest in our operated acreage and an approximate 39% working interest in our non-operated acreage. As of December 31, 2021, we had interests in approximately 891 gross / 822 net vertical and 298 gross / 219 net horizontal producing wells, of which we operate 804 vertical and 218 horizontal wells. With 474 potential gross horizontal drilling locations (299 operated / 175 non-operated) in the Midland Basin as of December 31, 2021, we are focused on developmental drilling and completion operations in the area.

We continue to pursue acreage trades and bolt-on acreage acquisitions in the Midland Basin with the intent of increasing our operated acreage and drilling inventory, drilling and completing longer laterals and realizing greater operating efficiencies.

Delaware Basin

Upon the consummation of the Chisholm Acquisition on February 15, 2022, we acquired approximately 36,100 net acres located in the Delaware Basin in New Mexico with approximately 85% held by production and approximately 92% operated. We now have interests in approximately 333 gross / 169 net producing wells, of which we operate 190 gross / 149 net producing wells. We have identified approximately 414 gross / 237 net potential drilling locations in this acreage.

Eagle Ford Trend

As of December 31, 2021, we had approximately 12,700 net leasehold acres in the Eagle Ford Trend, primarily in the crude oil window in Fayette, Gonzales and Karnes counties which include 37 gross / 32 net operated producing wells and 83 gross / 36 net non-operated wells.

Our Business Strategy

We believe that the recent trend of consolidation in the industry environment will continue and will result in further consolidation opportunities. We continue to pursue value-accretive and scale-enhancing consolidation opportunities, as we believe we are in a position to operate effectively despite volatility in commodity prices. We are focusing our attention on acquisition and corporate merger opportunities that would increase the scale of our operations in a financially accretive manner, without materially altering our debt metrics in relation to our cash flows and capital structure. In addition, we believe that our recent track record of successful consolidation will create further consolidation opportunities for us based on our increased scale, financial strength and success at acquiring and integrating assets in a financially prudent manner. At the same time, we will seek to block up acreage in the Midland Basin and Delaware Basin that would allow for longer horizontal laterals and should therefore provide for higher economic returns. In summary, we believe we are well qualified to be a consolidator which would increase the scale of our operations and add value to our shareholders.

Our current business strategy is to focus on the economic development of our existing acreage, increase our acreage and horizontal well locations in the Midland and Delaware Basins and increase stockholder value through the following:

- developing our acreage and profitably growing our production while seeking to maximize operating cash flows;
- operating our properties efficiently and continuing to improve our operating margins;
- deploying capital efficiently by drilling multi-well pads, reducing drilling times and increasing completions per day;
- leveraging both our increased operational and financial scale to achieve economies related to such scale where available;
- operating our assets in a safe and environmentally sensitive manner;
- continuing to hedge commodity prices as opportunities arise;
- pursuing value-accretive acquisition and corporate merger opportunities, which could increase the scale and profitability of our operations;
- maximizing operating margins and corporate level cash flows by minimizing operating and overhead costs;
- expanding our acreage positions and drilling inventory in our primary areas of interest through acquisitions and farm-in opportunities, with an emphasis on operated positions;
- blocking up acreage to allow for longer horizontal lateral drilling locations which provide higher economic returns; and
- maintaining a strong balance sheet and financial flexibility.

Our Strengths

We believe that the following strengths are beneficial in achieving our business goals:

- history of successful asset acquisitions and merger transactions;
- extensive horizontal development potential in two of the most oil rich basins of the United States;
- experienced management team with substantial technical and operational expertise;
- ability to attract technical personnel with experience in our core area of operations;
- operating control over the majority of our production and development activities;
- financial discipline;
- conservative balance sheet;
- commitment to cost efficient operations;
- a management team that is well known and respected throughout the industry; and
- ability to efficiently integrate acquisitions, allowing us to improve operating margins, as well as reducing lead time on additional acquisition opportunities.

COVID-19

Despite the recoveries in commodity prices, recent surges from COVID-19 variants continue to impact the global economy, disrupt global supply chains and may create significant volatility and disruption of financial and commodity markets. The extent of the impact of the COVID-19 pandemic on 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, including how the pandemic and measures taken in response to its impact on demand for oil and natural gas, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations. There is uncertainty around the extent and duration of disruption, including any resurgence, and we expect that the longer the duration of any such disruption, the greater the adverse impact may be on our business.

Operational Status

As a producer of oil, natural gas and NGLs, we are recognized as an essential business under various federal, state and local regulations related to the COVID-19 pandemic. We have continued to operate as permitted under these regulations while taking mitigation efforts and steps to protect the health and safety of our employees. The safety of our employees is paramount, and we have emphasized the respective guidelines to support our mitigation efforts. Our field personnel are performing their job responsibilities and practicing mitigation guidelines with no issues to date. While our non-field personnel returned to the office in mid-2020 and were fully in the office during 2021 with minimal disruptions, we remain flexible to working remotely, using information technology in which we previously invested if needed. We have managed and conducted both field and non-field functions effectively thus far, including our day-to-day operations, our accounting and financial reporting systems and our internal control over financial reporting. We will continue to focus on the health and safety of our employees in conformity with the applicable jurisdictional mitigation guidelines. We will continue to monitor CDC guidelines and respond appropriately.

Operational/Financial Challenges

It is difficult to model and predict how our operations and financial status may change as a result of COVID-19. In our industry, any forecast, plans and changes to operations and financial status are a function of commodity prices. If oil prices decline due to a resurgence of COVID-19, we believe we can continue to operate and produce our properties at a minimum in a cash flow neutral position for the next 12 months. A significant driver in the future may be the financial institutions' view on commodity prices with respect to borrowing base redeterminations. If a resurgence of COVID-19 triggers additional volatility in our business or global economies, our borrowing base could be reduced. Significant reductions in the borrowing base under our Credit Agreement could create a borrowing base deficiency depending on our loans then outstanding which may lead to a default. We believe global as well as national mitigation efforts currently being implemented to fight COVID-19 have had, and may continue to have, a material impact on commodity prices and may continue to present significant challenges to our industry.

The effects of COVID-19, including a substantial decrease in economic activity, have contributed to significant credit, debt and equity market volatility. Similar to other producers in our business, we experienced volatility in the price of our Class A Common Stock.

Organizational Structure

Earthstone is the sole managing member of EEH, with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Energy Corp., a corporation organized under the laws of British Columbia ("Lynden Corp"), and Lynden Corp's wholly-owned consolidated subsidiary, Lynden USA, Inc. ("Lynden US") and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US.

Operational Risks

Oil and natural gas exploitation, development and production involve a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will acquire, discover or produce additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental leakage or spills of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce our available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position and cash flows. For further discussion of these risks see *Item 1A. Risk Factors* of this report.

Marketing and Customers

We market the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2021, two purchasers accounted for 34% and 13%, respectively, of our revenue during the period. For the year ended December 31, 2020, three purchasers accounted for 32%, 15% and 12%, respectively, of our revenue during the period. For the year ended December 31, 2019, three purchasers accounted for 30%, 14% and 12%, respectively, of our revenue during the period. No other customer accounted for more than 10% of our revenue during these periods. If a major customer stopped purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a materially adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products in our area of operations with well-established markets and numerous purchasers.

Transportation

During the planning stage of our prospective and productive units and acreage, we consider required flow-lines, gathering and delivery infrastructure. Our oil is transported from the wellhead to our tank batteries or delivery points through our flow-lines or gathering systems. Purchasers of our oil take delivery (i) at a pipeline delivery point or (ii) at our tank batteries for transport by truck. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems. We have implemented a Leak Detection and Repair program, or LDAR, to locate and repair leaking components including valves, pumps and connectors in order to minimize the emission of fugitive volatile organic compounds and hazardous air pollutants. In addition, we install vapor recovery units in our newly installed tank batteries which also reduces emissions.

Our produced salt water is generally moved by pipeline connected to our operated salt water disposal wells or by pipeline to commercial disposal facilities.

Commodity Hedging

Consistent with our disciplined approach to financial management, we have an active commodity hedging program through which we seek to hedge a meaningful portion of our expected oil and gas production, reducing our exposure to downside commodity prices and enabling us to protect cash flows and maintain liquidity to fund our capital program.

Competition

The domestic oil and natural gas industry is intensely competitive in the acquisition of acreage, production and oil and gas reserves and in producing, transporting and marketing activities. Our competitors include national oil companies, major oil and natural gas companies, independent oil and natural gas companies, drilling partnership programs, individual producers, natural gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers. Many of our competitors are large, well-established companies. They may be able to pay more for seismic information and lease rights on prospective oil and natural gas properties and to define, evaluate, bid for and purchase a greater number of properties, than our financial or human resources permit. Our ability to acquire additional properties in the future, and our ability to fund the acquisition of such properties, will be dependent upon our ability to evaluate and select suitable properties and to consummate related transactions in a highly competitive environment.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Segment Information and Geographic Area

Operating segments are defined under accounting principles generally accepted in the United States ("GAAP") as components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on our organization and management, we have only one reportable operating segment, which is oil and natural gas acquisition, exploration, development and production. All of our operations are currently conducted in Texas and New Mexico.

Seasonality of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas drilling, completion and production activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced, depends on numerous factors beyond our control, the effect of which cannot be accurately predicted or anticipated. Some of these factors include, without limitation, the availability of other domestic and foreign production, the marketing of competitive fuels, the proximity and capacity of pipelines, fluctuations in supply and demand, the availability of a ready market, the effect of United States federal and state regulation of production, refining, transportation and sales and general national and worldwide economic conditions. Additionally, we may experience delays in marketing natural gas production and fluctuations in natural gas prices and we may experience short-term delays in marketing oil due to trucking and refining constraints. There is no assurance that we will be able to market significant amounts of oil or natural gas produced, or, if such oil or natural gas is marketed, that favorable prices can be obtained.

The United States natural gas market has undergone several significant changes over the past few decades. The majority of federal price ceilings were removed in 1985 and the remainder were lifted by the Natural Gas Wellhead Decontrol Act of 1989. Thus, currently, the United States natural gas market is operating in a free market environment in which the price of gas is determined by market forces rather than by regulations. At the same time, the domestic natural gas industry has also seen a dramatic change in the manner in which gas is bought, sold and transported. In most cases, natural gas is no longer sold to a pipeline company. Instead, the pipeline company now primarily serves the role of transporter and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and NGLs, we are unable to accurately predict future oil, natural gas and NGLs prices or the overall effect, if any, that the decline in demand for and the oversupply of such products will have on our financial condition or results of operations.

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 natural gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of our oil and natural gas properties. Our oil and natural gas properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, participation agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under various agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and other agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the quantity and value of our reserves. We believe that the burdens and obligations affecting our oil and natural gas properties are common in our industry with respect to the types of properties we own.

Operational Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory and regulatory provisions affecting drilling, completion, and production activities, including, but not limited to, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Moreover, the current administration has indicated that it expects to impose additional federal regulations limiting access to and production from federal lands. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, while some states, including New Mexico, allow the forced pooling or integration of land and leases to facilitate development, other states including Texas, where we operate, rely primarily or exclusively on voluntary pooling of land and leases. Accordingly, it may be difficult for us to form spacing units and therefore difficult to develop a project if we own or control less than 100% of the leasehold. 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, and impose specified requirements regarding the ratability of production. On some occasions, local authorities have imposed moratoria or other restrictions on exploration, development and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration, development and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and negatively affects profitability. 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.

Regulation of Transportation of Natural Gas

The transportation and sale, or resale, of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Sales of Oil, Natural Gas and NGLs

The prices at which we sell oil, natural gas and NGLs are not currently subject to federal regulation and, for the most part, are not subject to state regulation. FERC, however, regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Similarly, the price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. FERC regulates the transportation of oil and liquids on interstate pipelines under the provision of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate transportation of oil, NGLs, and other products, is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. In addition, while sales by producers of natural gas and all sales of crude oil, condensate, and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Changes in FERC or state policies and regulations or laws may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action that FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Environmental Regulations

Our operations are also subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency (the "EPA") issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a well or production related facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Beyond existing requirements, new programs and changes in existing programs, may affect our business including oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct on certain categories of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances found at the site. Under CERCLA, these potentially responsible persons may be subject to strict, joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances, but we are not presently aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act of 1976 ("RCRA"), and comparable state statutes, regulate the generation, treatment, storage, transportation, disposal and clean-up of hazardous and solid (non-hazardous) wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA's solid (non-hazardous) waste provisions. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain oil and natural gas exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent handling, disposal and clean-up requirements. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our, as well as the oil and natural gas E&P industry's, costs to manage and dispose of generated wastes, which could have a material adverse effect on the industry as well as on our business.

From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

The federal Clean Water Act and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including jurisdictional wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. In September 2015, the EPA and U.S. Army Corps of Engineers (the "Corps") rule defining the scope of federal jurisdiction over Waters of the United States (the "WOTUS rule") became effective. Following the change in U.S. Presidential Administrations, there have been several attempts to modify or eliminate this rule. For example, on January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows the definition of "waters of the United States" relative to the prior 2015 rulemaking. In November 2021, the EPA and the Corps issued a proposed rule to broaden the applicability of the definition of WOTUS. The agencies did not announce a date for official publication in the Federal Register of the new rule. However, future rulemakings regarding the definition of WOTUS will likely be subject to litigation. As a result of these developments, the scope of federal jurisdiction under the Clean Water Act is uncertain at this time.

The process for obtaining permits has the potential to delay our operations. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. The Clean Water Act and analogous state laws provide for administrative, civil and criminal penalties for unauthorized discharges and, together with the Oil Pollution Act of 1990 ("OPA"), impose rigorous requirements for spill prevention and response planning, as well as substantial potential liability for the costs of removal, remediation, and damages in connection with any unauthorized discharges.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program, and related state programs regulate the drilling and operation of saltwater disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. In New Mexico, the New Mexico Oil Conservation Division ("NMOCD") administers the UIC program for all injection wells that are related to oil and natural gas production. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. Permits must be obtained before drilling saltwater disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. In 2021, the NMOCD announced a new plan for responding to increased seismic activity in the Permian Basin. Under the new plan, pending permits for wastewater injection in certain areas will be subject to additional reporting and monitoring requirements. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. In particular, the well completion technique known as hydraulic fracturing which is used to stimulate production of oil and natural gas has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations in order to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

The SDWA regulates the underground injection of substances through the 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. However, legislation has been proposed in recent sessions of Congress to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process.

Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the fracturing process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment ("CWT") facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability

Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards 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 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, New Mexico has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. If new or more stringent state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

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, use of water and the potential for impacts to surface water, groundwater and the environment generally. Several lawsuits and enforcement actions have been initiated across the country 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 that specific chemicals used in the fracturing process could adversely affect groundwater. 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 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 newly enacted or potential federal, state or local laws governing hydraulic fracturing.

From time to time, legislation has been introduced, but not enacted, in the U.S. Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. On January 28, 2020, Senate Bill 3247 was introduced and if enacted as proposed, would ban hydraulic fracturing nationwide by 2025.

Air Emissions

The federal Clean Air Act ("CAA") and comparable state laws restrict emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

In 2012 and 2016, the EPA issued New Source Performance Standards to regulate emissions of sources of volatile organic compounds ("VOCs"), sulfur dioxide, air toxics and methane from various oil and natural gas exploration, production, processing and transportation facilities. On May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the Trump Administration directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rule making to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified, and existing oil and gas facilities. Given the long-term trend toward increasing regulation, future federal Greenhouse Gas ("GHG") regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. In November 2021, the EPA proposed new source performance standards and emissions guidelines to reduce methane and other pollution from new and existing sources in the oil and gas industry. The proposed rule would include, among other things, a comprehensive monitoring program for new and existing well sites, zero-emissions standards for new and existing pneumatic controls, and standards to eliminate venting of associated gas and requirements for the capture and sale of natural gas where a sales line is available. If adopted, these requirements could increase our costs to operate and control pollution. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. Until these rules are formally adopted, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

In October 2015, the EPA announced that it was lowering the primary National Ambient Air Quality Standards ("NAAQS") for ozone from 75 parts per billion to 70 parts per billion. Since that time, the EPA has issued area designations with respect to ground-level ozone. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion rather than lower them further. However, as discussed above, that action could be subject to reversal following the Biden Administration's January 2021 executive order. In 2022, the New Mexico Environment Department is expected to issue final rules imposing more stringent limits on ozone pollution from the oil and gas industry operating in the state. Reclassification of areas of state implementation of the revised NAAQS could result in stricter permitting requirements, delay, or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Moreover, the NMOCD recently adopted new rules, which require oil and gas operators to capture 98 percent of their natural gas waste by the end of 2026. The new rules went into effect on May 25, 2021. While the State of Texas has not formally conducted a recent rulemaking related to air emissions, scrutiny of oil and natural gas operations and the rules affecting them have increased in recent years. For example, the EPA and environmental non-governmental organizations have conducted flyovers with optical gas imaging cameras to survey emissions from oil and natural gas production facilities and transmission infrastructure. In addition, the RRC has increased oversight related to flaring, with reporting reviews and site inspections. While none of these activities increases our compliance obligations, they signal the potential for increased enforcement and possible rulemaking in the future.

Climate Change

In response to findings that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish construction and operating permit reviews for GHG emissions certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the Department of Transportation (the "DOT"), implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is an agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020. President Biden pledged the renewed participation of the United States on his first day in office. In November 2021, the United States participated in the United Nations Climate Change Conference in Glasgow, Scotland, United Kingdom ("COP26"). COP26 resulted in a pact among approximately 200 countries, including the United States, called the Glasgow Climate Pact. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. In conjunction with COP26, the United States committed to an economy-wide target of reducing net greenhouse gas emissions by 50-52 percent below 2005 levels by 2030. Also in November 2021, President Biden signed a $1 trillion dollar infrastructure bill into law. The new infrastructure law includes several climate-focused investments, including upgrades to power grids to accommodate increased use of renewable energy and expansion of electric vehicle infrastructure. Although it is not possible at this time to predict what additional domestic legislation may be adopted in light of the Paris Agreement or the Glasgow Climate Pact, or how legislation or new regulations that may be adopted based on the Paris Agreement or the Glasgow Climate Pact to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations and could decrease demand for oil and natural gas.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. For example, the New Mexico Environment Department has adopted regulations to restrict the venting or flaring of methane from both upstream and midstream operations.

Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. We also are aware that the SEC intends to propose new and additional rules regarding company disclosure of climate change risk. We will monitor and comply with any such promulgated rules.

Threatened and endangered species, migratory birds and natural resources

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act (“ESA”), the Migratory Bird Treaty Act (“MBTA”) and the Clean Water Act. The U.S. Fish and Wildlife Service (“FWS”) may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. As a result of a 2011 settlement agreement, the FWS was required to determine whether to identify more than 250 species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result. Similar protections are offered to migratory birds under the MBTA. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds, we believe that we are in substantial compliance with the ESA and the MBTA, and we are not aware of any proposed ESA listings that will materially affect our operations. Nevertheless, we are monitoring proposed listings by the FWS, such as the January 2022 proposal to list the Sacramento Mountains checkerspot butterfly in New Mexico, to ensure continued compliance. The federal government in the past has issued indictments under the MBTA to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. In January 2020, a new U.S. Department of the Interior (“DOI”) rule went into effect clarifying that only the intentional taking of protected migratory birds is subject to prosecution under the MTBA. In December 2021, however, that rule was revoked, and a new rule took effect reinstating the prohibition on incidental takes under the MTBA. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce our oil and natural gas reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Hazard communications and community right to know

We are subject to federal and state hazard communication and community right to know statutes and regulations. These regulations, including, but not limited to, the federal Emergency Planning & Community Right-to-Know Act, govern record keeping and reporting of the use and release of hazardous substances and may require that information be provided to state and local government authorities, as well as the public.

Occupational Safety and Health Act

We are subject to a number of federal and state laws and regulations, including OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may have an impact to our operations. These changes include among other items; record keeping and reporting, revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry and requirements for a safety and health management system. In addition, OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

State Regulation

Texas and New Mexico regulate 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 and New Mexico currently impose a severance tax on oil production of 4.6% and 3.75%, respectively, and a severance tax on natural gas and NGL production of 7.5% and 3.75%, respectively. 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 allowable 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 our stockholders 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.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration, development and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2021, nor do we anticipate that such expenditures will be material in 2022.

Employees

As of December 31, 2021, we had 81 full-time employees, of which 12 are management, 17 are technical personnel, 17 are administrative personnel and 35 are field operations employees. Our employees are not covered under a collective bargaining agreement nor are any employees represented by a union. We consider all relations with our employees to be satisfactory.

Office Locations

Our corporate headquarters are located at 1400 Woodloch Forest Drive, the Woodlands, Texas, with an additional office located at 600 North Marienfeld Street, Midland, Texas.

Information about our Executive Officers

The following table sets forth, as of March 1, 2022, certain information regarding the executive officers of Earthstone:

Name	Age	Position
Frank A. Lodzinski	72	Executive Chairman of the Board
Robert J. Anderson	60	President and Chief Executive Officer
Tony Oviedo	68	Executive Vice President, Accounting and Administration
Mark Lumpkin, Jr.	48	Executive Vice President and Chief Financial Officer
Steven C. Collins	57	Executive Vice President, Chief Operating Officer
Timothy D. Merrifield	66	Executive Vice President, Geological and Geophysical

The following biographies describe the business experience of our executive officers:

Frank A. Lodzinski has served as our Chairman since December 2014 and as Executive Chairman since April 1, 2020. He served as our Chief Executive Officer from December 2014 through March 2020. He also served as our President from December 2014 through April 2018. Previously, he served as President and Chief Executive Officer of Oak Valley Resources, LLC ("Oak Valley") from its formation in December 2012 until the closing of its strategic combination with Earthstone in December 2014. Prior to his service with Oak Valley, Mr. Lodzinski was Chairman, President and Chief Executive Officer of GeoResources, Inc. from April 2007 until its merger with Halcón Resources Corporation ("Halcón") in August 2012 and from September 2012 until December 2012 he conducted pre-formation activities for Oak Valley. He has over 47 years of oil and gas industry experience. In 1984, he formed Energy Resource Associates, Inc., which acquired management and controlling interests in oil and gas limited partnerships, joint ventures and producing properties. Certain partnerships were exchanged for common shares of Hampton Resources Corporation in 1992, which Mr. Lodzinski joined as a director and President. Hampton was sold in 1995 to Bellwether Exploration Company. In 1996, he formed Cliffwood Oil & Gas Corp. and in 1997, Cliffwood shareholders acquired a controlling interest in Texoil, Inc., where Mr. Lodzinski served as Chief Executive Officer and President. In 2001, Mr. Lodzinski was appointed Chief Executive Officer and President of AROC, Inc., to direct the restructuring and ultimate liquidation of that company. In 2003, AROC completed a monetization of oil and gas assets with an institutional investor and began a plan of liquidation in 2004. In 2004, Mr. Lodzinski formed Southern Bay Energy, LLC, the general partner of Southern Bay Oil & Gas, L.P., which acquired the residual assets of AROC, Inc., and he served as President of Southern Bay Energy, LLC upon its formation. The Southern Bay entities were merged into GeoResources in April 2007. Mr. Lodzinski has served as a director and member of the nominating and governance committee, audit committee and compensation committee of Yuma Energy, Inc. ("Yuma") since April 2019 and previously served on its audit committee from September 2014 to October 2016 and its compensation committee from October 2016 to April 2019. On April 15, 2020, Yuma, together with its subsidiaries, filed voluntary Chapter 11 petitions for relief under the United States Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of Texas. On October 20, 2020 the Bankruptcy Court issued an order to convert the Cases to a Chapter 7 liquidation. Mr. Lodzinski holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

Robert J. Anderson has served as our President and Chief Executive Officer since April 2020, having previously served as President since April 2018. From December 2014 through April 2018, he served as our Executive Vice President, Corporate Development and Engineering. Previously, he served in a similar capacity with Oak Valley from March 2013 until the closing of its strategic combination with the Company in December 2014. Prior to joining Oak Valley, he served from August 2012 to February 2013 as Executive Vice President and Chief Operating Officer of Halcón. Mr. Anderson was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012, ultimately serving as a director and Executive Vice President, Chief Operating Officer - Northern Region. He was involved in the formation of Southern Bay Energy in September 2004 as Vice President, Acquisitions until its merger with GeoResources in April 2007. From March 2004 to August 2004, Mr. Anderson was employed by AROC, a predecessor company to Southern Bay Energy, as Vice President, Acquisitions and Divestitures. Prior to March 2004 he was employed in technical and supervisory roles with Anadarko Petroleum Corporation, major oil companies including ARCO International/Vastar Resources, and independent oil companies, including Hugoton Energy, Hunt Oil and Pacific Enterprises Oil Company. His professional experience of over 30 years includes acquisition evaluation, reservoir and production engineering, field development, project economics, budgeting and planning, and capital markets. Mr. Anderson has a B.S. degree in Petroleum Engineering from the University of Wyoming and an MBA from the University of Denver.

Tony Oviedo has served as our Executive Vice President - Accounting and Administration (Principal Accounting Officer) since February 10, 2017. Mr. Oviedo has over 30 years of professional experience with both private and public companies. Prior to joining the Company, he was employed by GeoMet, Inc., where, since 2006, he served as the Senior Vice President, Chief Financial Officer, Chief Accounting Officer and Controller. In addition, prior to joining GeoMet, Mr. Oviedo was employed by Resolution Performance Products, LLC, where he was Compliance Director and has held positions as Chief Accounting Officer, Controller, and Director of Financial Reporting with various companies in the oil and gas industry. Prior to the aforementioned experience, he served in the audit practice of KPMG LLP's Energy Group. Mr. Oviedo holds a Bachelor's degree in Business Administration with a concentration in accounting and tax from the University of Houston and is a Certified Public Accountant in the state of Texas.

Mark Lumpkin, Jr. has over 23 years of experience including over 16 years of oil and gas finance experience. He has served as our Executive Vice President and Chief Financial Officer since August 2017. Immediately prior to joining Earthstone, he served as Managing Director at RBC Capital Markets in the Oil and Gas Corporate Banking group, beginning in 2011 with a focus on upstream and midstream debt financing. From 2006 until 2011, he was employed by The Royal Bank of Scotland ("RBS") in the Oil and Gas group within the Corporate and Investment Banking division, focusing primarily on the upstream subsector. Prior to RBS, he spent two years focused on capital markets and mergers and acquisitions primarily in the upstream sector at a boutique investment bank. Mr. Lumpkin graduated with a B.A. degree in Economics from Louisiana State University and graduated with a Master of Business Administration degree with a Finance concentration from Tulane University.

Steven C. Collins is a petroleum engineer with over 30 years of operations and related experience. He has served as our Executive Vice President and Chief Operating Officer since December 2014 (however, his title was Executive Vice President, Completions and Operations from December 2014 to January 2022 with the same position, authority and duties from December 2014 to present). Previously, he served in a similar capacity with Oak Valley from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Mr. Collins was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012 and directed field operations, including well completion, production and workover operations. Prior to employment by GeoResources, he served as Vice President of Operations for Southern Bay, AROC, and Texoil, and as a petroleum and operations engineer at Hunt Oil Company and Pacific Enterprises Oil Company. His experience includes Texas, Louisiana (onshore and offshore), North Dakota, Montana, and the Mid-Continent. Mr. Collins graduated with a B.S. degree in Petroleum Engineering from the University of Texas.

Timothy D. Merrifield has over 39 years of oil and gas industry experience. He has served as our Executive Vice President, Geology and Geophysics since December 2014. Previously, he served in a similar capacity with Oak Valley from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Prior to employment by Oak Valley, he served from August 2012 to November 2012 as a consultant to Halcón upon its merger with GeoResources, Inc. in August 2012. From April 2007 to August 2012, Mr. Merrifield led all geology and geophysics efforts at GeoResources. He has held previous roles at AROC, Force Energy, Great Western Resources and other independents. His domestic experience includes Texas, Louisiana (onshore and offshore), North Dakota, Montana, New Mexico, Rocky Mountain States, and the Mid-Continent. In addition, he has international experience in Peru and the East Irish Sea. Mr. Merrifield attended Texas Tech University.

Available Information

Our principal executive offices are located at 1400 Woodloch Forest Drive, Suite 300, The Woodlands, Texas 77380. Our telephone number is (281) 298-4246. You can find more information about us at our website located at www.earthstoneenergy.com. Our Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and any amendments to those reports are available free of charge on or through our website, which is not part of this report. These reports are available as soon as reasonably practicable after we electronically file these materials with, or furnish them to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

Item 1A. Risk Factors

Our business is subject to various risks and uncertainties in the ordinary course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. Readers should carefully consider the risk factors included below as well as those matters referenced in this report under "Cautionary Statement Concerning Forward-Looking Statements" and other information included and incorporated by reference into this report.

Summary Risk Factors

The following is a summary of the material risks and uncertainties we have identified, which should be read in conjunction with the more detailed description of each risk factor contained below.

General Business and Industry Risks

- Effects of the COVID-19 pandemic and responses;
- Volatility in prices for oil, natural gas and NGLs;
- Our oil and natural gas reserves are estimated and may not reflect the actual volumes we will recover, and we may be required to write down the carrying value of our proved properties under accounting rules;
- The borrowing base under our Credit Agreement is subject to periodic redetermination, and we are subject to interest rate risk under our Credit Agreement;
- Our ability to replace our oil and natural gas reserves;
- Uncertainties associated with estimating reserves and future net cash flows;
- Development of our reserves may take longer and may require higher levels of capital expenditures than we currently anticipate;
- The standardized measure of discounted future net cash flows from our estimated proved reserves may not be the same as the current market value of our estimated oil and natural gas reserves;
- Our level of success in development and production activities;
- Acquired properties may not produce as projected;
- Certain of our properties are in areas that may have been partially depleted or drained by offset wells, and certain of our wells may be adversely affected by actions of other operators;
- Multi-well pad drilling may result in volatility in our operating results;
- Unavailability or high cost of additional oilfield services;
- The unavailability or high cost of equipment, supplies, personnel and oilfield services used to drill and complete wells could adversely affect our ability to execute our development plans within our budget and on a timely basis;
- Ability to obtain required capital or financing on satisfactory terms;.
- A negative shift in stakeholder sentiment towards the oil and gas industry;
- Our ability to obtain future hedges and effectiveness of our commodity derivative activities;
- Competition in the oil and gas industry;
- Inability to complete additional acquisitions;
- Risks associated with recent transactions and exposure to contingent liabilities;
- Ability to effectively manage our expanded operations;
- Incurrence of substantial losses and liability claims as a result of our oil and gas operations, and risks our insurance may be inadequate to protect us against these losses;
- Exposure to significant compliance costs and liabilities;
- Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells;
- Extreme weather conditions affecting our ability to conduct drilling, completion and production activities;
- Adoption of climate change legislation or regulations restricting emissions of “greenhouse gases” and potential physical effects of climate change;
- Restrictions on drilling activities intended to protect certain species of wildlife;
- Geographic concentration of our operations;
- Changes in tax laws and regulations;
- Availability, use and disposal of water;
- Regulations that restrict our ability to acquire federal leases in the future;
- The marketability of our production is dependent upon gathering, processing and transportation facilities;
- Failure of third parties to fulfill their commitments to our projects;
- Incurrence of significant additional amounts of debt;
- We have limited control over activities on properties we do not operate;
- Cybersecurity threats and other disruptions in our electronic systems; and
- Our ability to attract, train and retain qualified personnel.

Risks Related to the Bighorn Acquisition

- Delays in completing the Bighorn Acquisition;
- Inability to successfully integrate Bighorn’s operations or to realize anticipated cost savings, revenues or other benefits of the Bighorn Acquisition;
- Limited recourse against Bighorn for losses and liabilities arising or discovered after closing;
- Incurrence of significant transaction and acquisition-related costs;
- We are subject to various uncertainties and contractual restrictions while the Bighorn Acquisition is pending;
- We may be the target of securities class action and derivative lawsuits which could result in substantial costs and may delay or prevent the Bighorn Acquisition from being completed; and

- Incurrence of substantial indebtedness in connection with the Bighorn Acquisition.

Risks Related to the Ownership of our Class A Common Stock

- As a holding company and the sole manager of EEH our only material asset is our equity interest in EEH;
- Our principal stockholders hold substantial voting power of our Common Stock;
- Holders of Class B Common Stock have the right to exchange their EEH Units and shares of Class B Common Stock for our Class A Common Stock;
- Future sales of our Class A Common Stock could reduce our stock price;
- We have no plans to pay dividends on our Class A Common Stock;
- Our Board of Directors can, without stockholder approval, cause preferred stock to be issued on terms that could adversely affect our common stockholders;
- The price of our Class A Common Stock may fluctuate significantly;
- Anti-takeover provisions could make a third-party acquisition difficult; and
- Our stockholders may act by unilateral written consent.

General Business and Industry Risks

Our business and operations have been and will likely continue to be adversely affected by the ongoing COVID-19 pandemic.

The spread of COVID-19 and variants caused, and is continuing to cause, severe disruptions in the worldwide and U.S. economies, including contributing to the reduced global and domestic demand for oil and natural gas, which has had and will likely continue to have an adverse effect on our business, financial condition and results of operations. Moreover, since the beginning of January 2020, the COVID-19 pandemic has caused significant disruption in the financial markets both globally and in the United States. The continued spread of COVID-19 and variants could also negatively impact the availability of key personnel necessary to conduct our business. If COVID-19 continues to spread or the response to contain or mitigate the COVID-19 pandemic through the development and availability of effective treatments and vaccines, including the vaccines approved by the FDA for emergency use in the U.S., is unsuccessful, we could continue to experience material adverse effects on our business, financial condition and results of operations. Due to the rapid development and fluidity of this situation, we cannot make any prediction as to the ultimate material adverse impact of the COVID-19 pandemic on our business, financial condition and results of operations.

Oil, natural gas and NGL prices are volatile. Their prices at times since 2014 have adversely affected, and in the future may adversely affect, our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments. Volatile and lower prices may also negatively impact our stock price.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenues, profitability, access to capital and future rate of growth. These hydrocarbons are commodities, and therefore, their prices may be subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, natural gas and NGL has been volatile. For example, during the period from January 1, 2014 through December 31, 2021, the WTI spot price for oil declined from a high of $107.95 per Bbl in June 2014 to -$36.98 per Bbl in April 2020. The Henry Hub spot price for natural gas has declined from a high of $8.15 per MMBtu in February 2014 to a low of $1.33 per MMBtu in September 2020. During 2021, WTI spot prices ranged from $47.47 to $85.64 per Bbl and the Henry Hub spot price of natural gas ranged from $2.43 to $23.86 per MMBtu. Likewise, NGL, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics, have experienced significant declines in realized prices since the fall of 2014. The prices we receive for oil, natural gas and NGL we produce and our production levels depend on numerous factors beyond our control, including:

- worldwide, regional and local economic and financial conditions impacting supply and demand;
- the level of global exploration, development and production;
- the level of global supplies, in particular due to supply growth from the United States;
- the price and quantity of oil, natural gas and NGLs imports to and exports from the U.S.;
- political conditions in or affecting other oil, natural gas and NGL producing countries and regions, including the current conflicts in the Middle East, Asia and Eastern Europe;
- the outbreak of military hostilities, including armed conflict between Russia and Ukraine and the potential destabilizing effect such conflict may pose for the European continent or the global oil and natural gas markets;
- actions of the OPEC and state-controlled oil companies relating to production and price controls;
- the extent to which U.S. shale producers become swing producers adding or subtracting to the world supply totals;

- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices and pricing differentials on local oil, natural gas and NGL price indices in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation, gathering and processing availability;
- weather conditions;
- technological advances affecting fuel economy, energy supply and energy consumption;
- the effect of energy conservation measures, alternative fuel requirements and increasing demand for alternatives to oil and natural gas;
- global or national health concerns, including health epidemics such as the COVID-19 pandemic at the beginning of 2020;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, natural gas and NGL prices have and may continue to reduce our cash flows and borrowing capacity. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our hydrocarbon reserves as existing reserves are depleted. A decrease in prices could render development projects and producing properties uneconomic, potentially resulting in a loss of mineral leases. Low commodity prices have, at times, caused significant downward adjustments to our estimated proved reserves, and may cause us to make further downward adjustments in the future. Furthermore, our borrowing capacity could be significantly affected by decreased prices. A sustained decline in oil, natural gas and NGL prices could adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligations under the Credit Agreement to the extent our outstanding borrowings exceed the redetermined borrowing base and could otherwise materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower oil, natural gas and NGL prices may typically cause a decline in the market price of our shares.

As a result of previous low prices for oil, natural gas and NGL, we may be required to take significant future write-downs of the financial carrying values of our properties in the future.

Accounting rules require that we periodically review the carrying value of our proved and unproved properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to significantly write-down the financial carrying value of our oil and natural gas properties, which constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are recorded.

A write-down could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved oil and natural gas reserves, if operating costs or development costs increase over prior estimates, or if exploratory drilling is unsuccessful.

The capitalized costs of our oil and natural gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, we would record impairment charges to reduce the capitalized costs of such field to our estimate of the field’s fair market value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce our earnings and stockholders’ equity and could adversely affect our stock price.

We periodically assess our properties for impairment based on future estimates of proved and non-proved reserves, oil and natural gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge cannot be reversed at a later date even if price increases of oil and/or natural gas occur and in the event of increases in the quantity of our estimated proved reserves.

If oil, natural gas and NGL prices fall below current levels for an extended period of time and all other factors remain equal, we may incur impairment charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are recorded. See *Note 7. Oil and Natural Gas Properties* to the *Notes to Consolidated Financial Statements* included in this report for additional information.

Any significant reduction in our borrowing base under our Credit Agreement may negatively impact our liquidity and, consequently, our ability to fund our operations, including capital expenditures, and we may not have sufficient funds to repay borrowings under our Credit Agreement or any other obligation if required as a result of a borrowing base redetermination.

Availability under the Credit Agreement is currently subject to a borrowing base of $825 million, as increased with the closing of the Chisholm Acquisition on February 15, 2022. The borrowing base is subject to scheduled semiannual redeterminations (on or about May 1 and November 1), as well as other lender-elective borrowing base redeterminations. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the Credit Agreement. Reductions in estimates of our oil, natural gas and NGL reserves may result in a reduction in our borrowing base under the Credit Agreement (if prices are kept constant). Reductions in our borrowing base under the Credit Agreement could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in oil, natural gas and NGL reserve engineering techniques;
- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

As of December 31, 2021, we had $320 million of borrowings outstanding under the Credit Agreement with a borrowing base of $650 million. When adjusted to include the closing of the Chisholm Acquisition on February 15, 2022, we had $604 million of long-term debt outstanding under the Credit Agreement with a borrowing base of $825 million. We may make further borrowings under the Credit Agreement in the future. Any significant reduction in our borrowing base under the Credit Agreement as a result of borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, could have a material adverse effect on our financial position, results of operations and cash flows. Further, if the outstanding borrowings under the Credit Agreement were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess.

Unless we replace our reserves, our production and estimated reserves will decline, which may adversely affect our financial condition, results of operations and/or cash flows.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that may vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well, particularly horizontal wells. Estimates of the decline rate of an oil or natural gas well are inherently imprecise and may be less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our estimated future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of those reserves.

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by SEC regulations relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex and requires significant decisions, complex analyses and assumptions in evaluating available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Our actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance will likely materially affect the estimated quantities and the estimated value of our reserves. In addition, we may later adjust estimates of proved reserves to reflect production history, results of exploration and development activities, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

Quantities of estimated proved reserves are based on economic conditions in existence during the period of assessment. Changes to oil, natural gas and NGL prices in the markets for these commodities may shorten the economic lives of certain fields because it may become uneconomical to produce all recoverable reserves in such fields, which may reduce proved reserves estimates.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future estimated cash flows of those reserves, may also trigger impairment losses on certain properties, which may result in non-cash charges to earnings. See *Note 7. Oil and Natural Gas Properties* to the *Notes to Consolidated Financial Statements* included in this report.

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

At December 31, 2021, approximately 37% of our estimated proved reserves were classified as proved undeveloped. The development of our estimated proved undeveloped reserves of 54,012 MBoe will require an estimated $455.1 million of development capital over the next five years. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on successful drilling and completion results, future commodity prices, costs and economic assumptions that align with our internal forecasts, as well as access to liquidity sources, such as the capital markets, the Credit Agreement and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. Moreover, under the applicable SEC regulations, we may be required to write down our proved undeveloped reserves if we do not drill or have a development plan to drill wells within a prescribed five-year period. The estimated reserve data assumes that we will make specified capital expenditures to timely develop our reserves. Where estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations the actual capital expenditures may vary from estimated capital expenditures, development may not occur as scheduled and actual results may be less than estimated.

The standardized measure of discounted future net cash flows from our estimated proved reserves may not be the same as the current market value of our estimated oil and natural gas reserves.

A reader should not assume that the standardized measure of discounted future net cash flows from our estimated proved reserves set forth in this report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2021, 2020 and 2019, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas unweighted arithmetic average prices without giving effect to derivative transactions and costs in effect as of the date of the estimate, holding prices and costs constant through the life of the properties. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as: the actual prices we receive for oil and natural gas; the actual cost of development and production expenditures; the amount and timing of actual production; and changes in governmental regulations or taxation.

The timing of both our production and incurring expenses related to developing and producing oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our business or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for statutory income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the estimates included in this report which could have a material effect on the value of our estimated reserves.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our leaseholds. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Properties we acquire may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and include properties with which we do not have a long operational history. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of a property. We may be required to assume the risk of the physical condition of properties in addition to the risk that they may not perform in accordance with our expectations. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.

Future drilling and completion activities associated with identified drilling locations may be adversely affected by factors that could materially alter the occurrence or timing of their drilling and completion, which in certain instances could prevent production prior to the expiration date of mineral leases for such locations.

Although our management team has identified numerous potential drilling locations as a part of our long-range planning related to future drilling activities on our existing acreage, our ability to drill and develop these locations depends on a number of factors, which are beyond our control, including, the availability and cost of capital, oil, natural gas and NGL prices, drilling and production costs, the availability of drilling services and equipment, drilling results (including the impact of increased horizontal drilling density and longer laterals), lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory permits and approvals and other factors. In addition, we may alter the spacing between our anticipated drilling locations, which could impact the number of our drilling locations, the number of wells that we drill, and the volumes of oil and gas we ultimately recover. As such, our actual drilling and completion activities, may materially differ from those presently anticipated. Accordingly, it is uncertain to what degree that these potential drilling locations will be developed or if we will be able to produce significant oil, natural gas and NGLs from these or any other potential drilling locations. Unless production is established, in accordance with the terms of mineral leases that are associated with these locations, such leases could expire.

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

Many of our properties are in reservoirs that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations by us or other operators could cause depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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 from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

The unavailability or high cost of equipment, supplies, personnel and oilfield services used to drill and complete wells could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which activity has increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, has increased, as have the costs for those items. In addition, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. Such shortages or cost increases could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our acquisition, development and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could limit growth or lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition and development of oil and natural gas reserves. We expect to fund our 2022 capital expenditures with cash on hand, cash generated by operations, borrowings under the Credit Agreement and possibly through additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of high-quality drilling rigs and other services and equipment and regulatory, technological and competitive developments. A significant reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including: our proved reserves; the level of hydrocarbons we are able to produce from existing wells; the prices at which our production is sold; our ability to acquire, locate and produce reserves; and our ability to borrow under the Credit Agreement.

If our revenues or the borrowing base under the Credit Agreement decrease as a result of low oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. The failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production and would adversely affect our business, financial condition and results of operations.

A negative shift in stakeholder sentiment towards the oil and gas industry and increased attention to ESG matters and conservation matters could adversely affect our ability to raise equity and debt capital.

Much of the investor community has developed negative sentiment towards investing in our industry over the past few years. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain public and private fund management firms, pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on environmental, social and governance considerations. Certain other stakeholders have pressured private equity firms and commercial and investment banks to stop funding oil and gas projects. Such developments have resulted and could continue to result in downward pressure on the stock prices of oil and gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are 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 and recent activism directed at shifting funding away from companies with energy-related assets 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 access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

We have incremental cash inflows and outflows as a result of our hedging activities. To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

In an effort to achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we often enter into derivative instrument contracts for a portion of our oil and natural gas production, including fixed price swaps, basis swaps and costless collars. We recognize all derivatives as either assets or liabilities, measured at fair value, and recognize changes in the fair value of derivatives in current earnings. Accordingly, our earnings may fluctuate significantly and our results of operations may be significantly and adversely affected because of changes in the fair market value of our derivative instruments, especially during periods of oil and gas price increases. As our derivative instrument contracts expire, there is no assurance that we will be able to replace them comparably.

Derivative instruments can expose us to the risk of financial loss in varying circumstances, including, but not limited to, when: production is less than the volume covered by the derivative instruments; the counter-party to the derivative instrument defaults on its contractual obligations; there is an increase in the differential between the underlying price stated in the derivative instrument contract and actual prices received; or there are issues with regard to legal enforceability of such instruments.

For additional information regarding our hedging activities, please see Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Note 6. Derivative Financial Instruments* in the *Notes to Consolidated Financial Statements* included in this report.

The oil and natural gas industry is highly competitive, and our size may put us at a disadvantage in competing for resources.

The oil and natural gas industry is highly competitive particularly in the Permian Basin and the Delaware Basin where our properties and operations are concentrated. We compete with major integrated and larger independent oil and natural gas companies in seeking to acquire desirable oil and natural gas properties and leases and for the equipment and services required to develop and operate properties. Many of our competitors have financial and other resources that are substantially greater than ours, which makes acquisitions of acreage or producing properties at economic prices difficult. Significant competition also exists in attracting and retaining technical personnel, including geologists, geophysicists, engineers, landmen and other specialists, as well as financial and administrative personnel hence we may be at a competitive disadvantage to companies with larger financial resources than ours.

Failure to complete additional acquisitions could limit our potential growth.

Our future success is highly dependent on our ability to acquire and develop mineral leases and oil and gas properties with economically recoverable oil and natural gas reserves. Without continued successful acquisition of economically attractive development projects, our current estimated oil and natural gas reserves will decline due to continued production activities. Acquiring additional oil and natural gas properties, or businesses that own or operate such properties is an important component of our business strategy. If we identify an appropriate acquisition candidate, management may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. Our limited access to financial resources compared to larger, better capitalized companies may limit our ability to make future acquisitions. If we are unable to complete suitable acquisitions, it may be more difficult to replace and increase our reserves, and an inability to replace our reserves may have a material adverse effect on our financial condition and results of operations.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we consider information available in the public domain and information provided by the seller. In the event publicly available data is limited, then, by necessity, we may rely to a large extent on information that may only be available from the seller, particularly with respect to drilling and completion costs and practices, geological, geophysical and petrophysical data, detailed production data on existing wells, and other technical and cost data not available in the public domain. Accordingly, the review and evaluation of businesses or properties to be acquired may not uncover all existing or relevant data, obligations or actual or contingent liabilities that could adversely impact any business or property to be acquired and, hence, could adversely affect us as a result of the acquisition. These issues may be material and could include, among other things, unexpected environmental liabilities, title defects, unpaid royalties, taxes or other liabilities. If we acquire properties on an "as-is" basis, we may have limited or no remedies against the seller with respect to these types of problems.

The success of any acquisition that we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, assumptions related to future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are often inexact and subjective. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales or operations.

Our ability to achieve the benefits that we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations. Management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business opportunities and concerns. The challenges involved in the integration process may include retaining key employees and maintaining employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding acquired properties.

Our future results will suffer if we do not effectively manage our expanded operations.

As a result of our recent acquisitions, the size and geographic footprint of our business has increased. Our future success will depend, in part, upon our ability to manage this expanded business, which may pose substantial challenges for management, including challenges related to the management and monitoring of new operations and basins and associated increased costs and complexity. We may also face increased scrutiny from governmental authorities as a result of the increase in the size of our business. There can be no assurances that we will be successful or that we will realize the expected benefits currently anticipated from our recent acquisitions.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations, including our drilling operations.

Oil and natural gas exploration, development and production activities are subject to numerous significant operating risks, including the possibility of:

- unanticipated, abnormally pressured formations;
- significant mechanical difficulties, such as stuck drilling and service tools and casing collapses;
- blowouts, fires and explosions;
- personal injuries and death;
- uninsured or underinsured losses; and
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination.

Any of these operating hazards could cause damage to properties, reduced cash flows, serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages, which could expose us to significant liabilities. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

The nature of our business and assets exposes us to significant compliance costs and liabilities.

Our operations involving the exploration, development and production of hydrocarbons are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment as well as protection of the environment, operational safety, and related employee health and safety matters. Laws and regulations applicable to us include those relating but not limited to the following: land use restrictions; delivery of our oil and natural gas to market; drilling bonds and other financial responsibility requirements; spacing of wells; air emissions; property unitization and pooling; habitat and endangered species protection, reclamation and remediation; containment and disposal of hazardous substances, oil field waste and other waste materials; drilling permits; use of saltwater injection wells, which affects the disposal of saltwater from our wells; safety precautions; prevention of oil spills; operational reporting; and taxation and royalties.

Compliance with these laws and regulations is a significant cost of doing business. Failure to comply with applicable laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory and remedial liabilities; the issuance of injunctions that may restrict, inhibit or prohibit our operations; and claims of damages to property or persons.

Some environmental laws and regulations impose strict liability, which means that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of prior operators of properties we acquired or of other third parties. Similarly, some environmental laws and regulations impose joint and several liability, meaning that we could be held responsible for more than our share of a particular reclamation or other obligation, and potentially the entire obligation, where other parties were involved in the activity giving rise to the liability. In addition, we may be required to make large and unanticipated capital expenditures to comply with applicable laws and regulations, for example by installing and maintaining pollution control devices. Similarly, our actual plugging and abandonment obligations may be more than our estimates. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters, but we estimate that they will be material. Environmental risks are generally not fully insurable.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or in the future plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the SDWA to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Several states and local jurisdictions in which we operate also have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids.

We may be subject to regulation that restricts our ability to discharge water produced as part of our oil, natural gas and NGL production operations. Productive zones frequently contain water that must be removed for the oil, natural gas and NGL to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce oil, natural gas and NGL in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. We have entered into various water management services agreements in Texas and New Mexico which provide for the disposal of our produced water by established counterparties with large integrated pipeline networks. If these counterparties fail to perform, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase for a number of reasons, including if new laws and regulations require water to be disposed in a different manner.

More recently, federal and state governments have begun investigating whether the disposal of produced water into underground injection wells has caused increased seismic activity in certain areas. States such as Texas and New Mexico have adopted, or are considering adopting, laws and regulations that may restrict or prohibit oilfield fluid disposal in certain areas or underground disposal wells, and state agencies implementing those requirements may issue orders directing certain wells in areas where seismic incidents have occurred to restrict or suspend disposal well operations or impose standards related to disposal well construction and monitoring. For example, the RRC recently issued a notice to operators in the Midland area to reduce daily injection volumes following multiple earthquakes above a 3.5 magnitude over an 18-month period. The notice also required disposal well operators to provide injection data to RRC staff to further analyze seismicity in the area. In 2021, the NMOCD announced a new plan for responding to increased seismic activity in the Permian Basin. Under the new plan, pending permits for wastewater injection in certain areas will be subject to additional reporting and monitoring requirements. While we cannot predict the ultimate outcome of this notice, any action that temporarily or permanently restricts the availability of disposal capacity for produced water or other fluids may increase our costs or have other adverse impacts on our operations.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Extreme weather conditions, which could become more frequent or severe due to climate change, could adversely affect our ability to conduct drilling, completion and production activities in the areas where we operate.

Our exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes or freezing temperatures, which may cause a loss of production from temporary cessation of activity from regional power outages or lost or damaged facilities and equipment. Such extreme weather conditions could also impact access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGL we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. In September 2020, the Trump Administration revised prior regulations to rescind certain methane standards and remove the transmission and storage segments from the source category for certain regulations. However, shortly after taking office, President Biden issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies and similar agency actions promulgated during the prior administration that may be inconsistent with the current administration’s policies. In response, the U.S. Congress has approved, and President Biden has signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In November 2021, as required by President Biden’s executive order, the EPA proposed new regulations to establish comprehensive standards of performance and emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments. The EPA is currently seeking public comments on its proposal, which the EPA hopes to finalize by the end of 2022. Once finalized, the regulations will also need to be incorporated in state implementation plans and approved by EPA. However, all of these regulatory actions will likely be subject to legal challenges. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates elected to public office. President Biden has issued several executive orders focused on addressing climate change, including items that may impact our costs to produce, or demand for, oil and gas. Additionally, in November 2021, the Biden Administration released “The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050,” which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide. The Biden Administration is also considering revisions to the leasing and permitting programs for oil and gas development on federal lands. Litigation risks are also increasing, as a number of entities have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change. Suits have also been brought against such companies under shareholder and consumer protection laws, alleging that companies have been aware of the adverse effects of climate change but failed to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a “climate finance plan” and, separately, the Federal Reserve has joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

As a final note, climate change could have an effect on the severity of weather (including hurricanes, droughts and floods), sea levels, the arability of farmland, water availability and quality, and meteorological patterns. If such effects were to occur, our development and production operations have the potential to be adversely affected.

Potential adverse effects could include damages to our facilities from powerful winds, extreme temperatures, or rising waters in low lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non- routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect certain wildlife, such as those restrictions imposed under the federal ESA. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Our oil, natural gas and NGLs are sold in a limited number of geographic markets so an oversupply in any of those areas could have a material negative effect on the price we receive.

Our oil, natural gas and NGLs are primarily sold in two geographic markets in Texas and one in New Mexico which each have a fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with oil, natural gas and/or NGLs, it could have a material negative effect on the prices we receive for our products and therefore an adverse effect on our financial condition and results of operations. There is a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the United States. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut-in of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of oil and natural gas.

Potential future legislation or the imposition of new or increased taxes or fees may generally affect the taxation of oil and natural gas exploration and development companies and may adversely affect our operations and cash flows.

In past years, federal and state level legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key federal and state income tax provisions currently available to oil and natural gas exploration and development companies. For example, President Biden has set forth several tax proposals that would, if enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to, (i) an increase in the U.S. income tax rate applicable to corporations and (ii) the elimination of tax subsidies for fossil fuels. Congress could consider some or all of these proposals in connection with tax reform to be undertaken by the Biden administration. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on oil and natural gas extraction. The passage of any legislation as a result of these proposals and other similar changes in federal income tax laws or the imposition of new or increased taxes or fees on oil and natural gas extraction could adversely affect our operations and cash flows.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas and NGLs, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

Any change to government regulation or administrative practices may have a negative impact on our ability to operate and our profitability.

Oil and natural gas operations are subject to substantial regulation under federal, state and local laws relating to the exploration for, and the development, upgrading, marketing, pricing, taxation, and transportation of, oil and natural gas and related products and other associated matters. Amendments to current laws and regulations governing operations and activities of oil and natural gas exploration and development operations could have a material adverse impact on our business. In addition, there can be no assurance that income tax laws, royalty regulations and government programs related to our oil and natural gas properties and the oil and natural gas industry generally will not be changed in a manner which may adversely affect our progress or cause delays.

Permits, leases, licenses, and approvals are required from a variety of regulatory authorities at various stages of exploration and development. There can be no assurance that the various government permits, leases, licenses and approvals sought will be granted in respect of our activities or, if granted, will not be cancelled or will be renewed upon expiration. There is no assurance that such permits, leases, licenses, and approvals will not contain terms and provisions which may adversely affect our exploration and development activities.

The current presidential administration, acting through the executive branch and/or in coordination with Congress, already has ordered or proposed, and could enact additional rules and regulations that restrict our ability to acquire federal leases in the future.

We are affected by the adoption of laws, regulations and policy directives that, for economic, environmental protection or other policy reasons, could curtail exploration and development drilling for oil and gas. For example, in January 2021, President Biden signed an Executive Order directing the DOI to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government’s existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed, although litigation over the leasing pause remains ongoing. In February 2022, another judge ruled that the Biden Administration’s efforts to raise the cost of climate change in its environmental assessments, would increase energy costs and damage state revenues from energy production. This ruling has cause federal agencies to delay issuing new oil and gas leases and permits on federal lands and waters.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not own or control. If these facilities or systems are unavailable, our oil and natural gas production can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production is dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation and processing facilities owned by third parties. In general, we will not control these facilities, and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the hydrocarbons we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our hydrocarbons is dependent upon coordination among third parties that own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. These are risks for which we generally will not maintain insurance.

We operate or participate in oil and natural gas leases with third parties who may not be able to fulfill their commitments to our projects.

In some cases, we operate but own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

Use of debt financing may adversely affect our strategy and financial viability.

We may incur substantial additional debt to fund a portion of our future acquisition, development and/or operating activities. Any temporary or sustained inability to service or repay such debt will likely have a material adverse effect on our ability to access financing markets and pursue our operating strategies, as well as impair our ability to respond to adverse economic changes in oil and natural gas markets and the economy in general.

Because we cannot control activities on properties we do not operate, we cannot directly control the timing of exploitation. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Our ability to exercise influence over operations and costs for the properties we do not operate is limited. Our dependence on the operators and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to acquisition, exploration and development activities. The success and timing of development, exploitation and exploration activities on properties operated by others depend upon a number of factors that may be outside our control, including but not limited to: the timing and amount of capital expenditures; the operator’s expertise and financial resources; the approval of other participants in drilling wells; and the selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditures associated with the project. If we are not willing or able to fund required capital expenditures relating to a project when required by the majority owner(s) or operator, our interests in the project may be reduced or forfeited. Also, we could be responsible for plugging and abandonment costs, as well as other liabilities in excess of our proportionate interest in the property.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We are dependent on digital technologies including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees, business partners, and stockholders, analyze 3-D seismic and drilling information, estimate quantities of oil and natural gas reserves as well as other activities related to our business.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for the purposes of misappropriating assets or sensitive information, corrupting data, causing operational disruption, or result in denial-of-service on websites.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, data, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

Risks Related to the Bighorn Acquisition

Delays in completing the Bighorn Acquisition may substantially reduce the expected benefits of the Bighorn Acquisition.

Satisfying the conditions to, and completion of, the Bighorn Acquisition may take longer than, and could cost more than, we expect. Any delay in completing the Bighorn Acquisition or any additional conditions imposed in order to complete the Bighorn Acquisition may materially adversely affect the synergies and other benefits that we expect to achieve from the Bighorn Acquisition and the integration of the respective business. In addition, each of EEH and Bighorn has the right to terminate the Bighorn Agreement if the Bighorn Acquisition is not completed by May 16, 2022, subject to a limited right to extend the closing until July 13, 2022.

We may be unable to successfully integrate Bighorn's operations or to realize anticipated cost savings, revenues or other benefits of the Bighorn Acquisition.

Our ability to achieve the anticipated benefits of the Bighorn Acquisition, if consummated, will depend in part upon whether we can successfully integrate Bighorn's assets and operations into our existing business in a timely, efficient and effective manner. The beneficial acquisition of producing and non-producing properties and undeveloped acreage that can be economically developed, including the assets acquired from Bighorn, requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas and oil prices and their appropriate differentials;
- availability and cost of transportation of production to markets;
- availability and cost of drilling equipment and of skilled personnel;
- development and operating costs and potential environmental and other liabilities; and
- regulatory, permitting and similar matters.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we have performed, and will continue to perform, a review of the subject properties, including properties that are subject to certain customary acreage swaps in process, that we believe to be generally consistent with industry practices. Our review may not reveal all existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections will not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even if problems are identified, the contractual protection provided with respect to all or a portion of the underlying deficiencies may prove ineffective or insufficient. The integration process may be subject to delays or changed circumstances, and we can give no assurance that the acquired properties will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of the Bighorn Acquisition will materialize. Significant acquisitions, including the Bighorn Acquisition, and other strategic transactions may involve other risks that may cause negative impacts on our business, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired assets and operations with those of our existing assets and operations while carrying on our ongoing business; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

We will only have limited recourse against Bighorn regarding the properties acquired in the Bighorn Acquisition for losses and liabilities arising or discovered after closing.

Under the terms of the Bighorn Agreement, we will have only limited recourse against Bighorn for losses and liabilities arising or discovered after the closing of the Bighorn Acquisition. We have limited indemnification rights in the event of a breach of a representation or warranty by Bighorn, any environmental defect, a breach of a covenant by Bighorn and certain third-party costs related to title defects. We also have limited rights to assert title defects or environmental defects, and any claims for title defects which were not timely asserted by us by March 16, 2022 have been deemed waived. As is customary in oil and gas transactions, we have agreed to assume various liabilities associated with the Bighorn Acquisition, including environmental liabilities, plugging and abandonment obligations, and unpaid royalties, regardless of when such liabilities arose.

The representations and warranties provided by Bighorn are limited as to scope and in many cases, qualified by knowledge and materiality thresholds. We must bring any claims for indemnification for a breach of a representation or warranty not involving title defects within the time period after the closing specified in the Bighorn Agreement, and for many representations and warranties, this time period is limited to 12 months.

Indemnification claims are subject to an individual claim threshold of $100,000 and Bighorn is only required to indemnify us for claims totaling in excess of 2% of the purchase price, or approximately $17 million based on a $850 million purchase price for the Bighorn Agreement. In addition, our right of recovery in most circumstances is limited to $63.8 million. We have conducted, and will continue to conduct prior to closing, an investigation of the properties to be acquired in the Bighorn Acquisition, but our investigation may not uncover all events or conditions that might negatively affect the value of the assets within such time periods. The total amount of uncured title defect claims or unremedied environmental claims must be more than 2.5% of the purchase price, or $21.3 million, respectively, before we will be entitled to a downward adjustment to the purchase price consideration for either type of claim. The short period for asserting claims for indemnification increases the likelihood that we may incur or uncover liabilities for which we have no recourse.

In addition, we may be obligated to complete the closing of the Bighorn Acquisition, even if Bighorn may have breached certain representations, warranties or covenants, as long as the breaches do not result in a material adverse effect with respect to the properties to be acquired in the Bighorn Acquisition. In such instance, our post-closing right to indemnification for such breaches by Bighorn may be very limited, as described above.

We have incurred and expect to continue to incur significant transaction and acquisition-related costs in connection with the Bighorn Acquisition.

We have incurred and expect to continue to incur significant non-recurring expenses in connection with the Bighorn Agreement and consummation of the Bighorn Acquisition and related financings. Additional unanticipated costs may be incurred, including, without limitation, unexpected costs and other expenses in the course of the integration of the businesses of Earthstone and Bighorn. In addition, we cannot be certain that the elimination of duplicative costs or the realization of other efficiencies related to the integration of the two businesses will offset the integration costs in the near term, or at all.

We will be subject to various uncertainties and contractual restrictions while the Bighorn Acquisition is pending that could adversely affect our financial results.

Uncertainty about the effect of the Bighorn Acquisition on employees, service providers, suppliers and industry partners may have an adverse effect on us, and potentially on Bighorn’s operations. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Bighorn Acquisition is completed and for a period of time thereafter, and could cause service providers, suppliers and others who deal with Bighorn to seek to change their existing business relationships. Employee retention and recruitment may be particularly challenging prior to completion of the Bighorn Acquisition, as employees and prospective employees may experience uncertainty about their future roles with the combined company.

The pursuit of the Bighorn Acquisition and the preparation for the integration of the businesses of the two companies will place a significant burden on our management and internal resources. Any significant diversion of management attention away from ongoing business and any difficulties encountered in the transition and integration process could adversely affect our financial results or the financial results of the combined company.

We may be the target of securities class action and derivative lawsuits which could result in substantial costs and may delay or prevent the Bighorn Acquisition from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into significant acquisition agreements. Even if the lawsuits are without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Any such lawsuit could also seek, among other things, injunctive relief or other equitable relief, including a request to rescind parts of the Bighorn Agreement already implemented and to otherwise enjoin the parties from consummating the Bighorn Acquisition. If a plaintiff is successful in obtaining an injunction prohibiting completion of the Bighorn Acquisition, then that injunction may delay or prevent the Bighorn Acquisition from being completed, which may adversely affect our business, financial position and results of operation.

One of the conditions to the closing of the Bighorn Acquisition is that no injunction by any court or other tribunal of competent jurisdiction has been entered and continues to be in effect and no law has been adopted or is effective, in either case that prohibits or makes illegal the closing of the Bighorn Acquisition. Consequently, if a lawsuit is filed and a plaintiff is successful in obtaining an injunction prohibiting completion of the Bighorn Acquisition, then that injunction may delay or prevent the Bighorn Acquisition from being completed within the expected timeframe or at all, which may adversely affect our business, financial position and results of operations.

We expect to incur substantial indebtedness in connection with the Bighorn Acquisition, which combined with our current debt may limit our financial flexibility and adversely affect our financial results.

Under the Bighorn Agreement, we have agreed to pay $770 million of the purchase price in cash. As of December 31, 2021, after giving effect to the Chisholm Acquisition and the Bighorn Acquisition, we would have had approximately $1.094 billion of total long-term debt and additional borrowing capacity of approximately $231 million under our senior secured revolving credit facility, assuming that the borrowing base is increased to $1.325 billion upon the closing of the Bighorn Acquisition.

Any increase in our indebtedness could have adverse effects on our financial condition and results of operations, including:

- increasing the difficulty of satisfying our obligations with respect to our debt obligations;
- diverting a significant portion of our cash flows to service our indebtedness, which could reduce the funds available to us for operations and other purposes;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that we would be unable to pursue due to our indebtedness;
- limiting our ability to access the capital markets to raise capital on favorable terms;
- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- increasing our vulnerability to interest rate increases, as our borrowings under our senior secured revolving credit facility are at variable interest rates.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. Our future performance depends on many factors independent of the Bighorn Acquisition, some of which are beyond our control, such as general economic conditions and oil and natural gas prices. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt.

Risks Related to the Ownership of our Class A Common Stock

We are a holding company and the sole manager of EEH. Our only material asset is our equity interest in EEH and, accordingly, we are dependent upon distributions from EEH to cover our corporate and other overhead expenses and pay taxes.

We are a holding company and the sole manager of EEH. We have no material assets other than our equity interest in EEH. We have no independent means of generating revenue. We expect EEH to reimburse us for our corporate and other overhead expenses, and to the extent EEH has available cash, we intend to cause EEH to make distributions to the holders of membership units of EEH (“EEH Units”), including us, as well as our wholly owned subsidiaries, Lynden Corp and Lynden US, in an amount sufficient to cover all applicable U.S. federal, state and local income taxes and non-U.S. tax liabilities of Earthstone, if any, at assumed tax rates. We will likely be limited, however, in our ability to cause EEH and its subsidiaries to make these and other distributions due to the restrictions under the Credit Agreement. To the extent that we need funds, and EEH or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Our principal stockholders hold substantial voting power of our Class A Common Stock and Class B Common Stock.

Holders of Class A Common Stock and our Class B Common Stock, $0.001 par value per share ("Class B Common Stock"), will vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or Earthstone's Third Amended and Restated Certificate of Incorporation, as amended (the "Certificate of Incorporation"). Subsequent to the IRM Acquisition and the Chisholm Acquisition, EnCap and the Warburg Parties may be deemed to beneficially own approximately 38.0% and 21.4%, respectively, of our voting interests and, along with their affiliates, could limit the ability of our other stockholders to approve transactions they may deem to be in the best interests of our Company or delaying or preventing changes in control or changes in our management.

As long as EnCap and certain of its affiliates and the Warburg Parties continue to control a significant amount of our outstanding voting securities, they will have the authority to exercise significant influence over management and all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. Also, in any of these matters, the interests of our management team may differ or conflict with the interests of our stockholders. In addition, EnCap and its affiliates and the Warburg Parties may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential acquisition candidates or industry partners. EnCap and its affiliates and the Warburg Parties may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Moreover, this concentration of stock ownership may also adversely affect the trading price of our Class A Common Stock to the extent investors perceive a disadvantage in owning stock of a company with stockholders who own such a significant percentage of our voting securities.

Bold Holdings (controlled by EnCap) and its permitted transferees have the right to exchange their EEH Units and shares of Class B Common Stock for our Class A Common Stock pursuant to the terms of the EEH LLC Agreement.

As of March 1, 2022, there were approximately 34.3 million shares of our Class A Common Stock that are issuable upon redemption or exchange of EEH Units and shares of Class B Common Stock that are held by Bold Holdings, an investment fund managed by EnCap, or its permitted transferees. Pursuant to the First Amended and Restated Limited Liability Company Agreement of EEH (the "EEH LLC Agreement"), subject to certain restrictions therein, holders of EEH Units and our Class B Common Stock are entitled to exchange such EEH Units and shares of Class B Common Stock for shares of our Class A Common Stock at any time.

Future sales of our Class A Common Stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity may dilute your ownership in us.

We may sell additional shares of Class A Common Stock or securities convertible into shares of our Class A Common Stock in subsequent offerings. Pursuant to the Securities Purchase Agreement, Earthstone has agreed to issue 280,000 shares of Preferred Stock which will convert into approximately 25.2 million shares of Class A Common Stock automatically on the 20th calendar day after Earthstone mails a definitive information statement to holders of its Common Stock notifying them that holders of a majority of the outstanding shares of Common Stock have consented to the conversion feature of the Preferred Stock and the issuance of Class A Common Stock upon conversion of the Preferred Stock. Additionally, we cannot predict the size of other future issuances of our Class A Common Stock or other securities convertible into Class A Common Stock or the effect, if any, that future issuances and sales of shares of our Class A Common Stock will have on the market price of our Class A Common Stock. Sales of substantial amounts of our Class A Common Stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A Common Stock.

We have no plans to pay dividends on our Class A Common Stock. Stockholders may not receive funds without selling their shares.

We do not anticipate paying any cash dividends on our Class A Common Stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. In addition, the Credit Agreement does not allow EEH to make any significant payments to us, which makes it highly unlikely that we would be in a position to pay cash dividends on our Class A Common Stock.

Our Board of Directors can, without stockholder approval, cause preferred stock to be issued on terms that could adversely affect our common stockholders.

Under the Certificate of Incorporation, our Board is authorized to cause Earthstone to issue up to 20,000,000 shares of preferred stock, of which none are issued and outstanding as of the date of this report; provided, however, we have agreed to issue 280,000 shares of Preferred Stock upon the closing of the Securities Purchase Agreement. Each share of Preferred Stock will be convertible into 90.0900900900901 shares of Class A Common Stock or an aggregate of approximately 25.2 million shares of Class A Common Stock. Also, our Board, without stockholder approval, may determine the price, rights, preferences, privileges, and restrictions, including voting rights, of those shares. If the Board causes shares of preferred stock to be issued, the rights of the holders of our Class A Common Stock and Class B Common Stock would likely be subordinate to those of preferred holders and therefore could be adversely affected. The Board's ability to determine the terms of preferred stock and to cause its issuance, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could have the effect of making it more difficult for a third-party to acquire a majority of our outstanding voting stock or otherwise seek to acquire us. Shares of preferred stock issued by us could include voting rights, or even super voting rights, which could shift the ability to control Earthstone to the holders of the preferred stock. Preferred stock could also have conversion rights into shares of Class A Common Stock at a discount to the market price of the Class A Common Stock which could negatively affect the market for our Class A Common Stock. In addition, preferred stock could have preference in the event of liquidation of Earthstone, which means that the holders of preferred stock would be entitled to receive the net assets of Earthstone distributed in liquidation before the Class A common stockholders receive any distribution of the liquidated assets.

The price of our Class A Common Stock may fluctuate significantly, which could negatively affect us and holders of our Class A Common Stock.

Our Class A Common Stock trades on the New York Stock Exchange. The trading price of our Class A Common Stock may fluctuate significantly in response to a number of factors, many of which are beyond our control. Adverse events including changes in production volumes, worldwide demand and prices for crude oil and natural gas, regulatory developments, and changes in securities analysts' estimates of our financial performance could negatively impact the market price of our Class A Common Stock. General market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could also have a similar negative impact. The stock markets regularly experience price and volume volatility that affects many companies' stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our Class A Common Stock.

Anti-takeover provisions could make a third-party acquisition difficult.

The Certificate of Incorporation provides for a classified board of directors, with each member serving a three-year term. Provisions in the Certificate of Incorporation could make it more difficult for a third-party to acquire us without the approval of our Board. In addition, the Delaware corporate statutes also contain certain provisions that could make an acquisition by a third-party more difficult.

Our stockholders may act by unilateral written consent.

Under the Certificate of Incorporation and as expressly permitted by the Delaware General Corporation Law (the "DGCL"), any action required to be taken at any annual or special meeting of our stockholders, or any action which may be taken at any annual or special meeting of such stockholders, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, is signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Thus, consents of this type can be effected without the participation or input of minority stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties

Midland Basin

As of December 31, 2021, we had approximately 102,100 net acres in the core of the Midland Basin that are highly contiguous on a project-by-project basis which allow us to drill multi-well pads. Of this acreage, 94% is operated and 6% is non-operated. We hold an approximate 96% working interest in our operated acreage and an approximate 39% working interest in our non-operated acreage. As of December 31, 2021, we had interests in approximately 891 gross vertical and 298 gross horizontal producing wells, of which we operate 804 vertical and 218 horizontal wells. With 474 potential gross horizontal drilling locations (299 operated / 175 non-operated) in the Midland Basin as of December 31, 2021, we are focused on developmental drilling and completion operations in the area. We continue to pursue acreage trades or bolt-on acreage acquisitions in the Midland Basin with the intent of increasing our operated acreage and drilling inventory, drilling and completing longer laterals and realizing greater operating efficiencies.

During 2021, we completed and began producing from 19 gross / 15.4 net operated wells and 8 gross / 0.8 net non-operated wells. We exited 2021 with 14 gross / 13.7 net operated wells that were in various stages of drilling and completion, of which 5 gross / 5 net wells have been completed as of March 1, 2022. We expect to complete and bring the remaining 9 gross / 8.7 net wells online in the second quarter of 2022.

Consistent with our operations from the latter part of 2021, we are running two drilling rigs in the Midland Basin, and we plan to do so throughout 2022. We anticipate spudding 40 gross / 35.8 net operated wells and bringing online 40 gross / 36.7 net operated wells on our Midland Basin properties during 2022.

Delaware Basin

Upon the consummation of the Chisholm Acquisition on February 15, 2022, we acquired approximately 36,100 net acres located in the Delaware Basin, located in Lea County and Eddy County, New Mexico, with approximately 85% held by production and approximately 92% operated. We now have interests in approximately 333 gross / 168.6 net producing wells, of which we operate 190 gross / 149.5 net producing wells. We have identified approximately 414 gross / 237.1 net potential drilling locations in this acreage.

We are currently utilizing two drilling rigs on our recently acquired Chisholm acreage, and we plan to do so throughout 2022 and we plan to spud 20 gross / 11.8 net operated wells and bring online 18 gross / 11.6 net operated wells in the Delaware Basin.

Eagle Ford Trend

As of December 31, 2021, we held approximately 24,300 gross (12,700 net) leasehold acres primarily in Fayette, Gonzales and Karnes counties, Texas. The acreage is located in the crude oil window of the Eagle Ford shale trend of South Texas and is prospective for the Eagle Ford, Austin Chalk and Upper Eagle Ford formations. Our working interests range from approximately 15% to 100%.

As of December 31, 2021, we operated 37 gross producing wells and had non-operated interests in 83 gross producing wells. We have identified a total of 24 potential gross Eagle Ford drilling locations in this acreage. In addition, we may have additional future economic locations. The majority of our acreage is covered by an approximately 173 square mile 3-D seismic survey.

Oil and Natural Gas Reserves

As of December 31, 2021, all of our oil and natural gas reserves were located in the state of Texas. We expect to further develop these properties through additional drilling and completion operations. Our reserve estimates have been prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"), an independent petroleum engineering firm. The scope and results of CG&A's procedures are summarized in a letter which is included as an exhibit to this report. For further information on estimated reserves, including information on estimated future net cash flows and the standardized measure of discounted future net cash flows, please refer to the *Note 21. Supplemental Information On Oil and Gas Exploration and Production Activities (Unaudited)* in Part II, Item 8 of the *Notes to Consolidated Financial Statements* of this report.

As of December 31, 2021, our estimated proved reserves totaled 147,587 MBoe and had a PV-10 value of approximately $2,016.7 million (reconciled in "Non-GAAP Measures" below) and a Standardized Measure of Discounted Future Net Cash Flows of approximately $1,818.4 million, all of which relate to our properties in Texas. During 2021, we incurred approximately $130.5 million in capital expenditures, primarily drilling and completion costs. We expect to further develop our properties through additional drilling.

2021 Activity in Proved Reserves

From January 1, 2021 to December 31, 2021, our total estimated proved reserves increased 87% from 78,875 MBoe to 147,587 MBoe. Of that, estimated proved developed reserves increased 144% from 38,298 MBoe to 93,575 MBoe and estimated proved undeveloped reserves increased 33% from 40,577 MBoe to 54,012 MBoe. The most significant increase resulted from our consolidation efforts and related purchases of minerals in place.

Proved Reserves as of December 31, 2021

The below table sets forth a summary of our estimated crude oil, natural gas and NGL reserves as of December 31, 2021, based on the annual reserve estimate prepared by CG&A. In preparing this reserve report, CG&A evaluated 100% of our properties at December 31, 2021. The prices used in estimating proved reserves are based on the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period for the year. All prices and costs associated with operating wells were held constant in accordance with the SEC guidelines.

Our proved reserve categories as of December 31, 2021 are summarized in the table below:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)(2)	% of Total Proved	Undiscounted Future Net Cash Flows ($ in thousands)	PV-10 ($ in thousands)	Standardized Measure of Discounted Future Net Cash Flows ($ in thousands)	Future Capital Expenditures ($ in thousands)
PDP	33,306	184,239	24,870	88,884	60 %	$ 2,352,990	$ 1,283,778	$ 1,157,536	$ —
PDNP	2,518	6,760	1,047	4,692	3 %	158,783	87,919	79,273	14,950
PUD	25,251	93,882	13,114	54,011	37 %	1,419,598	644,989	581,563	455,058
Total proved (1)	61,075	284,881	39,031	147,587	100 %	$ 3,931,371	$ 2,016,686	$ 1,818,372	$ 470,008

(1) Includes 23.9 MMBbl of oil, 111.4 Bcf of natural gas and 15.3 MMBbl of NGLs reserves attributable to noncontrolling interests. Additionally, $788.8 million of PV-10 and $711.2 million of standardized measure of discounted future net cash flows were attributable to noncontrolling interests.

(2) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

Non-GAAP Measures

PV-10

PV-10 is a non-GAAP measure that differs from a measure under GAAP known as "standardized measure of discounted future net cash flows" in that PV-10 is calculated without including future income taxes. Management believes that the presentation of the PV-10 value of its oil and natural gas properties is relevant and useful to investors because it presents the estimated discounted future net cash flows attributable to our estimated proved reserves independent of our income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. We believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies because the timing and quantification of future income taxes is dependent on company-specific factors, many of which are difficult to determine. For these reasons, management uses and believes that the industry generally uses the PV-10 measure in evaluating and comparing acquisition candidates and assessing the potential rate of return on investments in oil and natural gas properties. PV-10 does not necessarily represent the fair market value of oil and natural gas properties. PV-10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The table below provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows (*in thousands*):

Present value of estimated future net revenues (PV-10) (1)	$	2,016,686
Future income taxes, discounted at 10%		(198,314)
Standardized measure of discounted future net cash flows (2)	$	1,818,372

(1) Includes $788.8 million attributable to noncontrolling interests.

(2) Includes $711.2 million attributable to noncontrolling interests.

Reserve Quantity Information

The following table illustrates our estimated net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated. The oil price as of December 31, 2021 is based on the respective 12-month unweighted average of the first of the month prices of the WTI spot prices which equates to $66.56 per barrel. The natural gas price as of December 31, 2021 is based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $3.60 per MMBtu. The NGL price used to value reserves as of December 31, 2021 averaged $30.16 per barrel. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials, resulting in the aforementioned oil, natural gas and NGL reserves as of December 31, 2021 being valued using prices of $65.64 per barrel, $3.01 per MMBtu and $30.16 per barrel, respectively. All prices are held constant in accordance with SEC guidelines.

A summary of our changes in quantities of proved oil, natural gas and NGL reserves for the year ended December 31, 2021 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Balance - December 31, 2020	40,090	111,215	20,249	78,875
Extensions and discoveries	7,016	49,846	6,532	21,856
Sales of minerals in place	(8)	(1)	—	(8)
Purchases of minerals in place	25,114	106,539	17,103	59,973
Production	(4,381)	(14,505)	(2,257)	(9,055)
Revision to previous estimates	(6,756)	31,787	(2,596)	(4,054)
Balance - December 31, 2021	61,075	284,881	39,031	147,587
Proved developed reserves:	35,824	190,999	25,917	93,575
Proved undeveloped reserves:	25,251	93,882	13,114	54,012

The table below presents the quantities of proved oil, natural gas and NGL reserves attributable to noncontrolling interests as of December 31, 2021:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Proved developed	14,011	74,702	10,137	36,598
Proved undeveloped	9,876	36,719	5,129	21,125
Total proved	23,887	111,421	15,266	57,723

Notable changes in proved reserves for the year ended December 31, 2021 included the following:

- *Extensions and discoveries.* In 2021, extensions and discoveries of 21.9 MMBoe were primarily the result of successful drilling results in the Midland Basin.
- *Purchases of minerals in place.* In 2021, we completed multiple acquisitions that resulted in 60.0 MMBoe in additional reserves, as disclosed in *Note 3. Acquisitions and Divestitures* in the *Notes to Consolidated Financial Statements*.
- *Revision to previous estimates.* In 2021, the downward revisions of prior reserves of 4.1 MMBoe consisted of changes in anticipated well densities and changes in performance and other economic factors totaling 9.2 MMBoe and 5.5 MMBoe, respectively, offset by a positive revision of 10.6 MMBoe related to changes in prices.

Proved Undeveloped Reserves

Proved undeveloped reserves ("PUDs") increased from 40,577 MBoe to 54,012 MBoe or 33%, as of December 31, 2021 compared to December 31, 2020. PUDs represent 37% of our total proved reserves. Certain previously booked PUDs were reclassified as proved developed reserves due to successful drilling efforts. Revisions of prior estimates include certain PUDs that were reclassified to unproved categories due to development plan changes and increased well spacing. In accordance with our December 31, 2021 year-end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within the five years of original classification.

Changes in our PUD reserves for the year ended December 31, 2021 were as follows (*in MBoe*):

Proved undeveloped reserves at December 31, 2020 (1)	40,577
Conversions to developed	(8,274)
Extensions and discoveries	20,521
Purchases of minerals in place	11,577
Revision to previous estimates	(10,389)
Proved undeveloped reserves at December 31, 2021 (2)	54,012

(1) Includes 21,737 MBoe attributable to noncontrolling interests.

(2) Includes 21,125 MBoe attributable to noncontrolling interests.

2021 Changes in Proved Undeveloped Reserves

Conversions to developed. In our year-end 2020 plan to develop its PUDs within five years, it was estimated that $41.1 million of capital would be expended in 2021 for the conversion of 13 gross / 10.5 net PUDs to add 6.7 MMBoe. In 2021, due to improved commodity prices, we spent $55.1 million to convert 16 gross / 13.1 net PUDs adding 8.3 MMBoe to developed.

Revision to previous estimates. Downward revisions of prior reserves of 10.4 MMBoe consisted of changes in anticipated well densities and changes in performance and other economic factors totaling 9.2 MMBoe and 2.9 MMBoe, respectively, offset by a positive revision of 1.7 MMBoe related to changes in prices.

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2021 (*$ in thousands*):

Years Ended December 31, (1)	Future Production (MBoe) (2)	Future Cash Inflows (3)	Future Production Costs	Future Development Costs	Future Net Cash Flows
2022	2,672	$ 142,171	$ 18,705	$ 231,755	$ (108,289)
2023	5,802	290,866	37,673	147,888	105,305
2024	6,885	326,645	42,730	75,415	208,500
2025	4,856	208,241	30,173	—	178,068
2026	3,542	147,700	22,846	—	124,854
Thereafter	30,255	1,228,430	317,270	—	911,160
Total	54,012	$ 2,344,053	$ 469,397	$ 455,058	$ 1,419,598

(1) Beginning in 2022 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from previous years. These production volumes, inflows, expenses, development costs and cash flows are limited to the PUD reserves and do not include any production or cash flows from the Proved Developed category which will also help to fund our capital program.

(2) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(3) Computation is based on SEC pricing of (i) $65.64 per Bbl (WTI-Cushing oil spot prices, adjusted for differentials), (ii) $3.01 per Mcf (Henry Hub spot natural gas price), as adjusted for location and quality by property, and (iii) $30.16 per Bbl for NGL.

PUD reserves are expected to be recovered from new wells on undrilled acreage or from existing wells where additional capital expenditures are required, such as from drilled but uncompleted ("DUC") wells. Our development plan contemplates production to commence from all these wells by 2025.

Historically, our drilling programs have been substantially funded from our cash flow and borrowings under our Credit Agreement. Based on current commodity prices and our current expectations over the next five years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings under the Credit Agreement.

Preparation of Reserve Estimates

We engaged an independent petroleum engineering consulting firm, CG&A, to prepare our annual reserve estimates and we have relied on CG&A's expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines.

The technical person primarily responsible for the preparation of the reserve report is W. Todd Brooker, President of CG&A. He graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. Mr. Brooker is a Registered Professional Engineer in the State of Texas (License No. 83462) and has more than 25 years of experience in the estimation and evaluation of oil and natural gas reserves. He is also a member of the Society of Petroleum Engineers.

Geoffrey A. Vernon, our Vice President of Reservoir Engineering and A&D, is responsible for reservoir engineering, is a qualified reserve estimator and auditor and is primarily responsible for overseeing CG&A during the preparation of our annual reserve estimates. His professional qualifications meet or exceed the qualifications of reserve estimators and auditors set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Natural Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include a Bachelor of Science degree in Chemical Engineering from Texas Tech University in 2007; a Master of Business Administration degree from Rice University in 2014; member of the Society of Petroleum Engineers since 2007; and more than 14 years of practical experience in estimating and evaluating reserve information with more than nine of those years being in charge of estimating and evaluating reserves.

We maintain adequate and effective internal controls over our reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are technical information, financial data, ownership interest and production data. The relevant field and reservoir technical information, which is updated, at least, annually, is assessed for validity when CG&A has technical meetings with our engineers, geologists, operations and land personnel. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in *Internal Control – Integrated Framework*, (2013 Version) issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to our internal controls, and they are incorporated in our reserve database as well and verified internally by our personnel to ensure their accuracy and completeness. Once the reserve database has been updated with current information, and the relevant technical support material has been assembled, CG&A meets with our technical personnel to review field performance and future development plans in order to further verify the validity of estimates. Following these reviews, the reserve database is furnished to CG&A so that it can prepare its independent reserve estimates and final report. The reserve estimates prepared by CG&A are reviewed and compared to our internal estimates by Mr. Vernon, our Vice President of Reservoir Engineering and A&D. Material reserve estimation differences are reviewed between CG&A and us, and additional data is provided to address the differences. If the supporting documentation will not justify additional changes, the CG&A reserves are accepted. In the event that additional data supports a reserve estimation adjustment, CG&A will analyze the additional data, and may make changes it solely deems necessary. Additional data is usually comprised of updated production information on new wells. Once the review is completed and all material differences are reconciled, the reserve report is finalized and our reserve database is updated with the final estimates provided by CG&A.

Net Oil, Natural Gas and NGL Production, Average Price and Average Production Cost

The net quantities of oil, natural gas and NGLs produced and sold by us for the years ended December 31, 2021, 2020 and 2019, the average sales price per unit sold (excluding hedges) and the average production cost per unit are presented below:

	Years Ended December 31,		
	2021	2020	2019
Sales Volumes:			
Oil (MBbl)	4,381	3,180	3,086
Natural gas (MMcf)	14,505	7,282	4,760
Natural gas liquids (MBbl)	2,257	1,198	1,022
Barrels of oil equivalent (MBoe)*	9,055	5,591	4,902
Average daily production (Boe per day)	24,809	15,276	13,429
Average prices realized:**			
Oil (per Bbl)	$ 67.83	$ 37.85	$ 55.71
Natural gas (per Mcf)	$ 3.50	$ 1.18	$ 0.82
Natural gas liquids (per Bbl)	$ 31.76	$ 13.03	$ 15.09
Barrels of oil equivalent (per Boe)	$ 46.34	$ 25.85	$ 39.02
Production cost per Boe	$ 5.45	$ 5.21	$ 5.85

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting. Our derivatives for 2021, 2020 and 2019 have been marked-to-market in our Consolidated Statements of Operations and both the realized and unrealized amounts are reported as other income/expense.

The following tables summarize the net quantities of oil, natural gas and NGLs produced and sold by us, the average sales price per unit sold (excluding hedges) and the average production cost per unit for each of our core areas for the years ended December 31, 2021, 2020 and 2019.

Midland Basin

	Years Ended December 31,		
	2021	2020	2019
Sales Volumes:			
Oil (MBbl)	3,817	2,687	2,599
Natural gas (MMcf)	14,263	7,079	4,558
Natural gas liquids (MBbl)	2,191	1,141	965
Barrels of oil equivalent (MBoe)*	8,385	5,007	4,324
Average daily production (Boe per day)	22,972	13,681	11,846
Average prices realized:**			
Oil (per Bbl)	$ 67.75	$ 37.68	$ 55.05
Natural gas (per Mcf)	$ 3.50	$ 1.15	$ 0.75
Natural gas liquids (per Bbl)	$ 31.81	$ 13.08	$ 15.07
Barrels of oil equivalent (per Boe)	$ 45.10	$ 24.83	$ 37.25
Production cost per Boe	$ 4.95	$ 4.81	$ 5.22

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

Eagle Ford Trend

	Years Ended December 31,		
	2021	2020	2019
Sales Volumes:			
Oil (MBbl)	565	493	487
Natural gas (MMcf)	243	204	202
Natural gas liquids (MBbl)	65	57	57
Barrels of oil equivalent (MBoe)*	670	584	578
Average daily production (Boe per day)	1,837	1,595	1,583
Average prices realized:**			
Oil (per Bbl)	$ 68.35	$ 38.82	$ 59.20
Natural gas (per Mcf)	$ 3.89	$ 1.95	$ 2.43
Natural gas liquids (per Bbl)	$ 29.94	$ 11.96	$ 15.41
Barrels of oil equivalent (per Boe)	$ 61.88	$ 34.62	$ 52.29
Production cost per Boe	$ 11.68	$ 8.61	$ 10.58

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

** Amounts exclude the impact of cash paid/received on settled derivative contracts as we did not elect to apply hedge accounting.

Gross and Net Productive Wells

The following table summarizes our gross and net productive oil and natural gas wells by area as of December 31, 2021. A net well represents our percentage of ownership of a gross well.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin	924	783	265	259	1,189	1,042
Eagle Ford Trend	120	69	—	—	120	69

Acreage

The following table summarizes our gross and net developed and undeveloped acreage by area and state as of December 31, 2021. Net acreage represents our percentage ownership of gross acreage.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin	28,125	22,669	87,719	79,453	115,844	102,122
Eagle Ford Trend	22,164	11,042	2,179	1,638	24,343	12,680
Texas	50,289	33,711	89,898	81,091	140,187	114,802

The following table summarizes, as of December 31, 2021, the portion of our gross and net acreage subject to expiration over the next three years if not successfully developed or renewed.

	Expiring Acreage							
	2022		2023		2024		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	559	535	40	10	1,336	609	1,935	1,154
Eagle Ford Trend	2,732	2,040	46	41	1,388	635	4,166	2,716
Total	3,291	2,575	86	51	2,724	1,244	6,101	3,870

Approximately 99% of the Midland Basin net acreage is held by production and approximately 85% of the Eagle Ford net acreage is held by production. On a combined basis, our total net acreage is approximately 97% held by production.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated.

	Years Ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	27	16	24	13	42	21
Dry(1)	—	—	—	—	1	—
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	27	16	24	13	42	21
Dry	—	—	—	—	1	—
Total	27	16	24	13	43	21

(1) The dry hole category includes one gross (0.2 net) non-operated well that was unsuccessful due to mechanical issues.

The figures in the table above do not include nine gross wells (7.3 net) that were drilled and uncompleted or in the process of being completed at December 31, 2021, all of which are classified as PUDs as of that date and are expected to begin producing in the first quarter of 2022.

Item 3. Legal Proceedings

In the ordinary course of business, we may be involved in litigation and claims arising out of our operations. As of December 31, 2021, and through the filing date of this report, we do not believe the ultimate resolution of any such actions or potential actions of which we are currently aware will have a material effect on our consolidated financial position or results of operations.

A description of our legal proceedings is included in *Note. 15. Commitments and Contingencies* in the *Notes to Consolidated Financial Statements* included in Item 8 of this report.

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

Shares of our Class A Common Stock are listed on the NYSE under the symbol "ESTE."

Holders

As of March 1, 2022, there were approximately 1,800 holders of record of our Class A Common Stock and eight holders of record of our Class B Common Stock. There is no public market for our Class B Common Stock.

Unregistered Sales of Equity Securities

None, except to the extent previously included by Earthstone in a Quarterly Report on Form 10-Q or Current Report on Form 8-K.

Dividends

We have never paid dividends on our Class A Common Stock or Class B Common Stock and do not have current plans to pay a dividend. Furthermore, the Credit Agreement restricts the payment of cash dividends. The payment of future cash dividends on our Class A Common Stock, if any, will be reviewed periodically by our Board and will depend upon, but not be limited to, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, our future business prospects and any restrictions imposed by our present or future financing arrangements.

Repurchase of Equity Securities

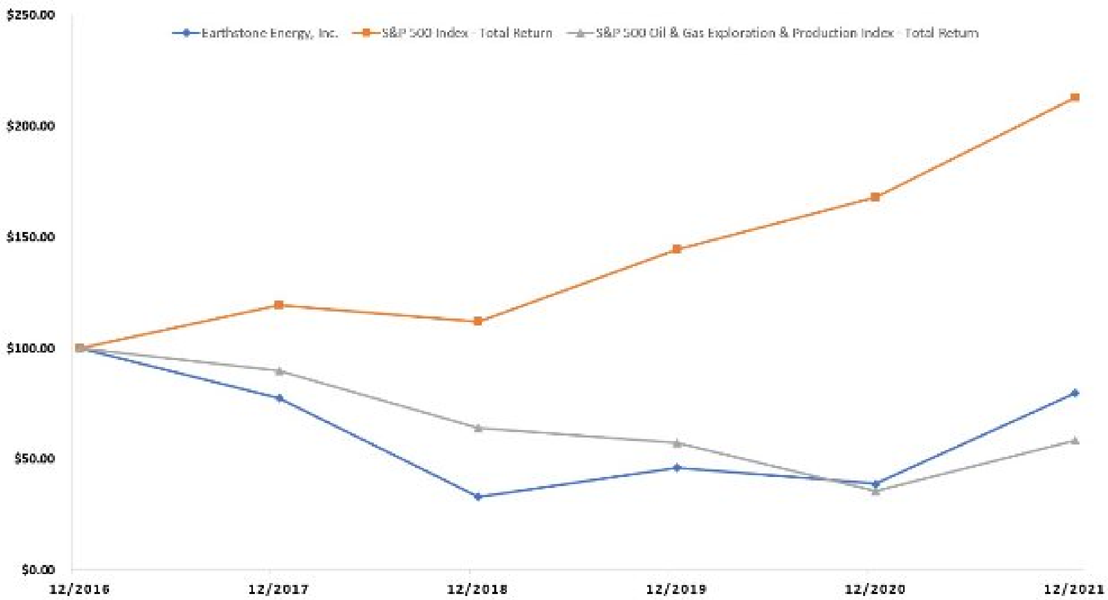
The following table sets forth information regarding our acquisition of shares of Class A Common Stock for the periods presented:

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs
October 2021	—	—	—	—
November 2021	—	—	—	—
December 2021	64,270	$ 11.28	—	—

(1) All of the shares were surrendered by employees (via net settlement) in satisfaction of tax obligations upon the vesting of restricted stock unit awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our Class A Common Stock.

Performance Graph

The following graph reflects a comparison of the cumulative total stockholder return of our Class A Common Stock beginning December 31, 2016 through December 31, 2021, relative to the cumulative total returns of the S&P 500 Index and the S&P Oil & Gas Exploration & Production Select Industry Index. The graph assumes the investment of $100 on December 31, 2016 in our Class A Common Stock and each index and the reinvestment of all dividends, if any. The identity of the companies included in the S&P Oil & Gas Exploration & Production Select Industry Index will be provided upon request.



	12/30/2016	12/29/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021
Earthstone Energy, Inc.	$100.00	$77.37	$32.90	$46.07	$38.79	$79.62
S&P 500 Index - Total Return	$100.00	$119.42	$111.97	$144.31	$167.77	$212.89
S&P 500 Oil & Gas Exploration & Production Index - Total Return	$100.00	$89.93	$64.10	$57.34	$35.46	$58.38

Item 6. Reserved

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

This discussion and other items in this Annual Report on Form 10-K contain forward-looking statements and information that are based on management's beliefs, as well as assumptions made by, and information currently available to, management. When used in this document, the words "believe," "anticipate," "estimate," "expect," "intend," "may," "will," "project," "forecast," "plan," and similar expressions are intended to identify forward-looking statements. Although management believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. These statements are subject to numerous risks, uncertainties and assumptions. See *Cautionary Statement Concerning Forward-Looking Statements* in this report. Certain of these risks are summarized in this report under *Item 1A. Risk Factors,* which you should read carefully in connection with our forward-looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated. We undertake no obligation to release publicly any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events.

For a discussion and analysis of our financial condition and results of operations for the year ended December 31, 2020 compared to December 31, 2019, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the year ended December 31, 2020, which was filed with the SEC on March 10, 2021.

Overview

We are a growth-oriented independent oil and gas company engaged in the acquisition and development of oil and gas reserves through activities that include the acquisition, drilling and development of undeveloped leases, asset and corporate acquisitions and mergers. Our operations are all in the upstream segment of the oil and natural gas industry and all our properties are onshore in the United States. Our assets are currently located in the Midland Basin in West Texas, the Eagle Ford Trend in South Texas, and the Delaware Basin in New Mexico.

Earthstone is the sole managing member of Earthstone Energy Holdings, LLC, a Delaware limited liability company (together with its wholly-owned consolidated subsidiaries, "EEH"), with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Corp, and Lynden Corp's wholly-owned consolidated subsidiary, Lynden US and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US (collectively, the "Company" "our," "we," "us," or similar terms).

Bighorn Agreement

On January 30, 2022, Earthstone, EEH, and Bighorn entered into the Bighorn Agreement. Pursuant to the Bighorn Agreement, EEH will acquire (the "Bighorn Acquisition") interests in oil and gas leases and related property of Bighorn located in the Midland Basin in West Texas, for a purchase price (the "Bighorn Purchase Price") of $770 million in cash and 6,808,511 shares of Class A Common Stock. The Bighorn Purchase Price is subject to customary purchase price adjustments with an effective date of January 1, 2022. In connection with the Bighorn Agreement, EEH deposited $50 million in cash into a third-party escrow account as a deposit pursuant to the Bighorn Agreement, which will be credited against the Bighorn Purchase Price upon closing of the Bighorn Acquisition. The Bighorn Acquisition is expected to close in the second quarter of 2022.

Credit Agreement

On January 30, 2022, Earthstone, EEH, as Borrower, Wells Fargo, as Administrative Agent, the lenders party thereto (the "Lenders") and the guarantors party thereto entered into an amended and restated Fifth Amendment (the "Amendment") to the Credit Agreement dated November 21, 2019, by and among EEH, as Borrower, Earthstone, as Parent, Wells Fargo, as Administrative Agent and Issuing Bank, Royal Bank of Canada, as Syndication Agent, Truist Bank, Citizens Bank, N.A., KeyBank National Association, U.S. Bank National Association, Fifth Third Bank, PNC Bank, National Association, and Bank of America, N.A., as Documentation Agents, and the Lenders party thereto (together with all amendments or other modifications, the "Credit Agreement"). Among other things, the Amendment increased the borrowing base and corresponding elected commitments from $650 million to $825 million upon the Chisholm Closing; provides that upon the closing of the Bighorn Acquisition, the borrowing base and corresponding elected commitments would increase to $1.325 billion, unless Earthstone completes a Notes Offering prior to the closing of the Bighorn Acquisition in which case the elected commitments will be reduced by the amount of the net proceeds from a Notes Offering up to $500 million; provides for an increase in interest rates by 0.50% in the event a Notes Offering has not been completed prior to the closing of the Bighorn Acquisition; provides mechanics relating to the transition from LIBOR to a benchmark replacement rate, SOFR, to be effective contemporaneously with the effectiveness of the amendment on January 30, 2022; adds certain hedging requirements relating to anticipated oil and natural gas production of the properties to be acquired pursuant to the Bighorn Acquisition; adjusts some financial covenants; redefines the limitations on certain restricted payments the Borrower may make; and made certain administrative changes to the Credit Agreement.

Securities Purchase Agreement

On January 30, 2022, Earthstone entered into the Securities Purchase Agreement with EnCap Fund XI and Post Oak to sell, in a private placement (the "Private Placement"), 280,000 shares of Preferred Stock, each share of which will be convertible into 90.0900900900901 shares of Class A Common Stock for anticipated gross proceeds of $280.0 million, at a price of $1,000.00 per share of Preferred Stock (or $11.10 per share of Class A Common Stock on an as-converted basis). The Private Placement is contingent upon the closing of the Bighorn Acquisition. The Company intends to use the net proceeds from the sale of the Preferred Stock to partially fund the Bighorn Acquisition. The Preferred Stock will convert automatically on the 20th calendar day after Earthstone mails a definitive information statement to holders of its Common Stock notifying them that holders of a majority of the outstanding shares of Common Stock have consented to the conversion feature of the Preferred Stock and the issuance of Class A Common Stock upon conversion of the Preferred Stock. As of January 30, 2022, Earthstone had received written consent for the conversion feature of the Preferred Stock and the issuance of the Class A Common Stock issuable upon conversion of the Preferred Stock from stockholders representing more than 50% of Earthstone's outstanding shares of Common Stock. As of the date of the Securities Purchase Agreement, EnCap and its affiliates beneficially owned approximately 46.5% of the outstanding voting power of Earthstone. Two members of the Board are employed by EnCap. The Securities Purchase Agreement and the Private Placement were evaluated and unanimously approved by the Audit Committee and unanimously approved by the Board.

Chisholm Acquisition

On February 15, 2022, Earthstone, EEH, and Chisholm, as seller, consummated the transactions contemplated in the Chisholm Agreement. At the closing of the Chisholm Agreement, among other things, EEH acquired (the "Chisholm Acquisition") interests in oil and gas leases and related property of Chisholm located in Lea County and Eddy County, New Mexico, for aggregate consideration consisting of: (i) approximately $314.7 million in cash, net of preliminary and customary purchase price adjustments and remains subject to post-closing settlement between EEH and Chisholm paid at the closing of the

Chisholm Acquisition, (ii) $70 million in cash to be paid as follows: $40 million to be paid six months after the closing of the Chisholm Acquisition and $30 million to be paid 12 months after the closing of the Chisholm Acquisition, subject to acceleration in the event that Earthstone receives gross proceeds of more than $450 million from a high yield bond offering or more than $50 million in gross proceeds from an offering of Class A Common Stock or preferred stock; and (iii) 19,417,476 shares of Class A Common Stock. See further discussion in *Note 3. Acquisitions and Divestitures* and *Note 14. Related Party Transactions* in the *Notes to Consolidated Financial Statements*.

Cash consideration for the Chisholm Acquisition was funded by borrowings under our senior secured revolving credit facility whose borrowing base was increased from $650 million to $825 million upon consummation of the Chisholm Acquisition.

Liquidity Update

As of March 1, 2022, we had approximately $1 million in cash and $652 million of long-term debt outstanding under our Credit Agreement, as amended, with a borrowing base of $825 million. With the $173 million of undrawn borrowing base capacity and $1 million in cash, we had total liquidity of approximately $174 million.

Areas of Operation

At present, our assets are located almost entirely in the Midland and Delaware Basins in West Texas and New Mexico, respectively, along with some oil and natural gas assets in the Eagle Ford Trend of South Texas.

Midland Basin

We believe that the Midland Basin continues to have attractive economics and we expect to continue growing our footprint through development drilling, acreage trades, asset acquisitions, and corporate merger and acquisition opportunities.

We continue to be active in acreage trades and acquisitions in the Midland Basin which generally allow for longer laterals, increased operated inventory and greater operating efficiency.

During 2021, we completed and began producing from 19 gross / 15.4 net operated wells and 8 gross / 0.8 net non-operated wells. We exited 2021 with 14 gross / 13.7 net operated wells that were in various stages of drilling and completion, of which 5 gross / 5 net wells have been completed as of March 1, 2022. We expect to complete and bring the remaining 9 gross / 8.7 net wells online in the second quarter of 2022.

Consistent with our operations from the latter part of 2021, we are running two drilling rigs in the Midland Basin, and we plan to do so throughout 2022. We anticipate spudding 40 gross / 35.8 net operated wells and bringing online 40 gross / 36.7 net operated wells on our Midland Basin properties during 2022.

Delaware Basin

Upon the consummation of the Chisholm Acquisition on February 15, 2022, we acquired approximately 36,100 net acres located in the Delaware Basin with approximately 85% held by production and approximately 92% operated. We now have interests in approximately 333 gross / 168.6 net producing wells, of which we operate 190 gross / 149.5 net producing wells. We have identified approximately 414 gross / 237.1 net potential drilling locations in this acreage.

We are currently utilizing two drilling rigs on our recently acquired Chisholm acreage, and we plan to do so throughout 2022 and we plan to spud 20 gross / 11.8 net operated wells and bring online 18 gross / 11.6 net operated wells in the Delaware Basin.

Results of Operations

Year ended December 31, 2021 compared to the year ended December 31, 2020

	Years Ended December 31,		
	2021	**2020**	**Change**
Sales volumes:			
Oil (MBbl)	4,381	3,180	38 %
Natural gas (MMcf)	14,505	7,282	99 %
Natural gas liquids (MBbl)	2,257	1,198	88 %
Barrels of oil equivalent (MBoe) (1)	9,055	5,591	62 %
Average daily production (BOE per day)	24,809	15,276	62 %
Average prices realized:			
Oil (per Bbl)	$ 67.83	$ 37.85	79 %
Natural gas (per Mcf)	$ 3.50	$ 1.18	197 %
Natural gas liquids (per Bbl)	$ 31.76	$ 13.03	144 %
Average prices adjusted for realized derivatives settlements:			
Oil ($/Bbl)	$ 52.32	$ 54.95	(5)%
Natural gas ($/Mcf)	$ 2.89	$ 1.42	104 %
Natural gas liquids ($/Bbl)	$ 31.76	$ 13.03	144 %
(In thousands)			
Oil revenues	$ 297,177	$ 120,355	147 %
Natural gas revenues	50,809	8,567	493 %
Natural gas liquids revenues	71,657	15,601	359 %
Total revenues	$ 419,643	$ 144,523	190 %
Lease operating expense	$ 49,321	$ 29,131	69 %
Production and ad valorem taxes	$ 26,409	$ 9,411	181 %
Impairment expense	$ —	$ 64,498	NM
Depreciation, depletion and amortization	$ 106,367	$ 96,414	10 %
General and administrative expense (excluding stock-based compensation)	$ 20,908	$ 18,179	15 %
Stock-based compensation	$ 21,014	$ 10,054	109 %
General and administrative expense	$ 41,922	$ 28,233	48 %
Transaction costs	$ 4,875	$ 622	684 %
Interest expense, net	$ (10,796)	$ (5,232)	106 %
Unrealized (loss) gain on derivative contracts	$ (40,795)	$ 3,855	(1,158)%
Realized (loss) gain on derivative contracts	$ (75,966)	$ 56,044	(236)%
(Loss) gain on derivative contracts, net	$ (116,761)	$ 59,899	(295)%
Income tax (expense) benefit	$ (1,859)	$ 112	(1,760)%

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equals one barrel of oil equivalent (Boe).

NM – Not meaningful

Results of Operations Highlights

The IRM Acquisition, the Eagle Ford Acquisitions, the Tracker Acquisition, the Sequel Acquisition, the Foreland Acquisition and the BCC Acquisition (collectively, the "Acquisitions") have had a significant and pervasive impact on our results of operations when compared to the prior year and, as it relates to the year ended December 31, 2020, diminished somewhat by operating results due to voluntary production shut-ins resulting from low commodity prices. In addition, commodity prices in 2021 have improved compared to the prior corresponding periods further impacting our results of operations. Below is a detailed discussion highlighting the impact of our recent acquisitions.

Oil revenues

For the year ended December 31, 2021, oil revenues increased by $176.8 million or 147% compared to 2020. Of the increase, $95.3 million was attributable to an increase in our realized price and $81.5 million was attributable to an increase in volume. Our average realized price per Bbl increased from $37.85 for the year ended December 31, 2020 to $67.83 or 79% for the year ended December 31, 2021. We had a net increase in the volume of oil sold of 1,202 MBbls or 38%, which included an increase of 1,562 MBbls related to the wells acquired in the Acquisitions and new wells coming online related to our 2021 drilling program, offset by a decrease of 360 MBbls in our other wells primarily resulting from natural declines and shut-ins resulting from Winter Storm Uri in February 2021.

Natural gas revenues

For the year ended December 31, 2021, natural gas revenues increased by $42.2 million or 493% compared to 2020. Of the increase, $25.3 million was due to increased sales volumes and $16.9 million was attributable to an increase in realized price. Our average realized price per Mcf increased 197% from $1.18 for the year ended December 31, 2020 to $3.50 for the year ended December 31, 2021. The total volume of natural gas produced and sold increased 7,223 MMcf or 99% which included an increase of 5,910 MMcf related to the wells acquired in the Acquisitions and an increase of 1,313 MMcf in our other wells primarily resulting from new wells coming online related to our 2021 drilling program, as well as prior year volumes being impacted by voluntary production shut-ins.

NGL revenues

For the year ended December 31, 2021, NGL revenues increased by $56.1 million or 359% compared to 2020. Of the increase, $33.6 million was attributable to higher sales volumes and $22.5 million was due to an increase in our realized price. The volume of NGLs produced and sold increased by 1,059 MBbls or 88%, which included an increase of 870 MBbls related to the wells acquired in the Acquisitions and an increase of 189 MBbls in our other wells primarily resulting from new wells coming online related to our 2021 drilling program, as well as prior year period volumes being impacted by voluntary production shut-ins.

Lease operating expense ("LOE")

LOE includes all costs incurred to operate wells and related facilities for both operated and non-operated properties. In addition to direct operating costs such as labor, repairs and maintenance, re-engineering and workovers, equipment rentals, materials and supplies, fuel and chemicals, LOE includes product marketing and transportation fees, insurance and overhead charges provided for in operating agreements.

LOE increased by $20.2 million or 69% for the year ended December 31, 2021 compared to 2020, primarily due to a $16.1 million increase resulting from the LOE of the properties acquired in the Acquisitions and a $4.1 million increase resulting from new wells coming online related to our 2021 drilling program, as well as prior year period volumes being impacted by voluntary production shut-ins.

Production and ad valorem taxes

Production and ad valorem taxes for the year ended December 31, 2021 increased by $17.0 million or 181% compared to 2020, due to a $10.6 million increase resulting from the properties acquired in the Acquisitions and a $6.4 million increase related to our existing wells resulting from improved commodity prices, as well as prior year period volumes being impacted by voluntary production shut-ins.

Impairment

During the year ended December 31, 2021, we did not record any non-cash impairments with respect to our oil and natural gas assets. During the year ended December 31, 2020, we recorded non-cash impairments totaling $64.5 million which consisted of $25.3 million to proved oil and natural gas properties, $21.6 million to unproved oil and natural gas properties and $17.6

million to goodwill. See *Note 7. Oil and Natural Gas Properties* in the *Notes to Consolidated Financial Statements* for a discussion of how impairments are measured.

Depreciation, depletion and amortization ("DD&A")

DD&A increased for the year ended December 31, 2021 by $10.0 million, or 10% compared to 2020, primarily due to a $28.9 million increase in DD&A related to the assets acquired in the Acquisitions, offset by an $18.9 million decrease in DD&A related to our other wells primarily resulting from lower prior year period volumes due to the impact of voluntary production shut-ins, as well as additional volumes added to the depletable base of our properties resulting from the impact of improved commodity prices on our estimated proved reserves.

General and administrative expense ("G&A")

G&A for the year ended December 31, 2021 increased by $13.7 million, or 48% compared to 2020, primarily due to an increase of $11.0 million in stock-based compensation expense of which $7.9 million resulted from the modification of an equity award and $3.1 million resulted from an increase in the market value of our Class A Common Stock. The remainder of the increase was due to $1.7 million resulting from the reinstatement of our short-term incentive program which was suspended in the prior year period and an increase of $1.0 million related to professional fees and lower administrative overhead reimbursements.

Transaction costs

For the year ended December 31, 2021, transaction costs increased by $4.3 million compared to 2020, primarily due to $6.1 million in legal and professional fees and severance costs primarily associated with the Acquisitions and other potential acquisitions, partially offset by $1.2 million of net reimbursements received related to the Olenik litigation. During the year ended December 31, 2020, we recorded transaction costs primarily due to legal, consulting and other fees of approximately $1.0 million related to the IRM Acquisition which was consummated on January 7, 2021 and $0.3 million related to other potential transactions, offset by net reimbursements of $0.7 million related to the business combination (the "Bold Transaction") pursuant to the Bold Contribution Agreement (as defined below) which closed on May 9, 2017.

Interest expense, net

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Interest expense increased from $5.2 million for the year ended December 31, 2020, to $10.8 million for the year ended December 31, 2021 due to higher average borrowings outstanding compared to the prior year primarily resulting from borrowings related to the Acquisitions. See *Note 12. Long-Term Debt* in the *Notes to Consolidated Financial Statements*.

(Loss) gain on derivative contracts, net

For the year ended December 31, 2021, we recorded a net loss on derivative contracts of $116.8 million, consisting of net realized losses on settlements of our commodity hedges of $76.9 million, partially offset by net realized gains on our interest rate swap of $0.9 million, along with unrealized mark-to-market losses of $41.2 million related to our commodity hedges, partially offset by unrealized mark-to-market gains of $0.4 million related to our interest rate swap. For the year ended December 31, 2020, we recorded a net gain on derivative contracts of $59.9 million, consisting of net realized gains on settlements of $56.0 million and unrealized mark-to-market gains of $3.9 million.

Income tax (expense) benefit

During the year ended December 31, 2021, the Company recorded total income tax expense of $1.9 million which included (1) deferred income tax expense for Lynden US of $0.9 million as a result of its share of the distributable income from EEH, (2) deferred income tax expense for Earthstone of $6.3 million as a result of its share of the distributable loss from EEH, which was offset by a valuation allowance as future realization of the net deferred tax asset cannot be assured and (3) current income tax expense of $0.63 million and (4) deferred income tax expense of $0.33 million related to the Texas Margin Tax. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2021.

During the year ended December 31, 2020, the Company recorded total income tax benefit of $0.11 million which included (1) deferred income tax expense for Lynden US of $0.15 million as a result of its share of the distributable income from EEH, (2) deferred income tax benefit for Earthstone of $0.61 million as a result of its share of the distributable loss from EEH, which was offset by a valuation allowance as future realization of the net deferred tax asset cannot be assured and (3) current income tax expense of $0.55 million offset by deferred income tax benefit of $0.51 million related to the Texas Margin Tax. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2020.

Liquidity and Capital Resources

We have significant undeveloped acreage and future drilling locations. Drilling horizontal wells, generally consisting of 7,500 to 12,000-foot lateral lengths, in the Midland and Delaware Basins is capital intensive. As of December 31, 2021, we had $4.0 million in cash and $320.0 million of long-term debt outstanding under our Credit Agreement with a borrowing base of $650.0 million. With the $330.0 million of undrawn borrowing base capacity and $4.0 million in cash, we had total liquidity of approximately $334.0 million. Subsequent to year-end, Earthstone closed on its previously announced Chisholm Acquisition and amended the Credit Agreement. As of March 1, 2022, we had approximately $1 million in cash and $652 million of long-term debt outstanding under our Credit Agreement, as amended, with a borrowing base of $825 million. With the $173 million of undrawn borrowing base capacity and $1 million in cash, we had total liquidity of approximately $174 million.

With two drilling rigs operating in the Midland Basin and two additional rigs operating in the Delaware Basin, we expect to spend $410-$440 million based on our current 2022 drilling plan. We believe we will have sufficient liquidity with cash flows from operations and borrowings under the Credit Agreement to meet our cash requirements for the next 12 months.

Working Capital

Working Capital (presented below) was a deficit of $89.2 million as of December 31, 2021 compared to a deficit of $20.8 million as of December 31, 2020, representing an increase in the deficit of $68.4 million. Of the $68.4 million increase in the working capital deficit, $50.3 million resulted from a decrease in the net fair value of our derivative contracts expected to settle in the 12 months subsequent to December 31, 2021 resulting from increased oil price futures as of December 31, 2021. The remaining decrease of $18.1 million primarily resulted from increased drilling in the current year. The components of working capital are presented below:

(in thousands)	December 31, 2021	December 31, 2020
Current assets:		
Cash	$ 4,013	$ 1,494
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	50,575	16,255
Joint interest billings and other, net of allowance of $19 and $19 at December 31, 2021 and 2020, respectively	2,930	7,966
Derivative asset	1,348	7,509
Prepaid expenses and other current assets	2,549	1,509
Total current assets	61,415	34,733
Current liabilities:		
Accounts payable	$ 31,397	$ 6,232
Revenues and royalties payable	36,189	27,492
Accrued expenses	31,704	16,504
Asset retirement obligation	395	447
Derivative liability	45,310	1,135
Advances	4,088	2,277
Operating lease liability	681	773
Finance lease liability	—	69
Other current liabilities	851	565
Total current liabilities	150,615	55,494
Working Capital (deficit)	**$ (89,200)**	**$ (20,761)**

We expect that changes in receivables and payables related to our pace of development, production volumes, changes in our hedging activities, realized commodity prices and differentials to NYMEX prices for our oil and natural gas production will continue to be the largest variables affecting our working capital.

We expect to finance future development activities with cash flows from operating activities, borrowings under the Credit Agreement and, various means of corporate and project financing. Additionally, we may continue to partially finance our drilling activities through the sale of participating rights to financial institutions or industry participants, and we could structure such arrangements on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate share of capital costs.

Cash Flows from Operating Activities

Cash flows provided by operating activities for the year ended December 31, 2021 increased to $230.9 million compared to $131.5 million for the year ended December 31, 2020, primarily due to the impact of oil and natural gas property acquisitions and the timing of payments and receipts partially offset by the cash settlement of derivative contracts as compared to the prior year.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2021 increased to $426.2 million from $87.8 million for the year ended December 31, 2020, primarily due to acquisitions of oil and gas properties.

Cash Flows from Financing Activities

Cash flows provided by financing activities were $197.9 million for the year ended December 31, 2021 as compared to cash flows used in financing activities of $56.0 million for the year ended December 31, 2020, primarily due to borrowings required to fund acquisitions of oil and gas properties.

Capital Expenditures

Our accrual basis capital expenditures for the years ended December 31, 2021, 2020 and 2019 were as follows:

	Years Ended December 31, *(In thousands)*		
	2021	2020	2019
Drilling and completions	$ 127,884	$ 66,580	$ 202,332
Leasehold costs	2,608	208	8,098
Total capital expenditures	$ 130,492	$ 66,788	$ 210,430

Hedging Activities

The following table sets forth our outstanding derivative contracts at December 31, 2021. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2022	Crude Oil Swap	2,768,250	$57.69
2022	Crude Oil Basis Swap(1)	3,832,500	$0.51
2022	Natural Gas Swap	5,900,000	$3.20
2022	Natural Gas Basis Swap(2)	9,100,000	$(0.26)
2023	Natural Gas Swap	1,375,000	$3.27

(1) The basis differential price is between WTI Midland Argus Crude and the WTI NYMEX.
(2) The basis differential price is between W. Texas (WAHA) and the Henry Hub NYMEX.

	Costless Collars			
Period	Commodity	Volume (Bbls / MMBtu)	Bought Floor ($/Bbl / $/MMBtu)	Sold Ceiling ($/Bbl / $/MMBtu)
2022	Crude Oil Costless Collar	730,000	$ 60.00	$ 73.73
2023	Crude Oil Costless Collar	365,000	$ 55.00	$ 71.75
2022	Natural Gas Costless Collar	4,037,500	$ 3.43	$ 5.10
2023	Natural Gas Costless Collar	888,000	$ 3.25	$ 5.13

Hedging Update

The following table sets forth our outstanding derivative contracts at March 1, 2022. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2022	Crude Oil Swap	3,930,750	$64.33
2022	Crude Oil Basis Swap(1)	4,322,500	$0.51
2023	Crude Oil Swap	1,277,500	$76.20
2023	Crude Oil Basis Swap(1)	730,000	$0.49
2022	Natural Gas Swap	8,782,000	$3.49
2022	Natural Gas Basis Swap(2)	9,100,000	$(0.26)
2023	Natural Gas Swap	3,670,000	$3.35
2023	Natural Gas Basis Swap(2)	25,550,000	$(1.28)
2024	Natural Gas Basis Swap(2)	25,620,000	$(1.04)

(1) The basis differential price is between WTI Midland Argus Crude and the WTI NYMEX.
(2) The basis differential price is between W. Texas (WAHA) and the Henry Hub NYMEX.

	Costless Collars			
Period	Commodity	Volume (Bbls / MMBtu)	Bought Floor ($/Bbl / $/MMBtu)	Sold Ceiling ($/Bbl / $/MMBtu)
2022	Crude Oil Costless Collar	1,740,000	$ 68.45	$ 82.57
2023	Crude Oil Costless Collar	1,715,500	$ 62.98	$ 80.34
2022	Natural Gas Costless Collar	14,987,500	$ 3.67	$ 5.47
2023	Natural Gas Costless Collar	13,188,000	$ 3.28	$ 4.84

Obligations and Commitments

We had the following contractual obligations and commitments as of December 31, 2021:

(In thousands)	2022	2023	2024	2025	2026	Thereafter
Debt [1]	$ 648	$ —	$ 320,000	$ —	$ —	$ —
Derivative liabilities	45,310	571	—	—	—	—
Asset retirement obligations	395	140	441	—	497	14,392
Office leases	696	595	605	152	—	—
Total	$ 47,049	$ 1,306	$ 321,046	$ 152	$ 497	$ 14,392

(1) 2022 amount represents interest payable under the Credit Agreement as of December 31, 2021.

Environmental Regulations

Our operations are subject to risks normally associated with the exploration for and the production of oil and natural gas, including blowouts, fires, and environmental risks such as oil spills or natural gas leaks that could expose us to liabilities associated with these risks.

In our acquisition of existing or previously drilled well bores, we may not be aware of prior environmental safeguards, if any, that were taken at the time such wells were drilled or during such time the wells were operated. We maintain comprehensive insurance coverage that we believe is adequate to mitigate the risk of any adverse financial effects associated with these risks.

However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still accrue to us. No claim has been made, nor are we aware of any liability which we may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations relating thereto.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other risks. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Oil and Natural Gas Properties

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire oil and natural gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells, geological and geophysical are charged to operations as incurred. Depreciation, depletion and amortization of the leasehold and development costs that are capitalized for proved oil and natural gas properties are computed using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers. Oil and natural gas properties are periodically assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group, but at least annually. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, and asset retirement obligations. Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board ("FASB"). The accuracy of our reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;
- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Our proved reserves information included in this report is based on estimates prepared by our independent petroleum engineers, CG&A. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2021. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations, and asset retirement obligations in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization

Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Natural Gas Properties

We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing the pretax future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds undiscounted future cash flows, the cost of the property is written down to “fair value,” which is determined based on expected future cash flows using discount rates commensurate with the risks involved, using prices and costs consistent with those used for internal decision making. Different pricing assumptions or discount rates could result in a different calculated impairment. We provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred.

Asset Retirement Obligation

Our asset retirement obligations (“AROs”) consist primarily of estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the field.

Derivative Instruments and Hedging Activity

We are exposed to certain risks relating to our ongoing business operations, such as commodity price risk. Derivative contracts are utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. We follow FASB Accounting Standards Codification (“ASC”) Topic 815, *Derivatives and Hedging,* to account for our derivative financial instruments. We do not enter into derivative contracts for speculative trading purposes. It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive. We did not post collateral under any of these contracts.

Our crude oil and natural gas derivative positions consist of fixed price swaps, basis swaps and costless collars. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum (sold ceiling) and a minimum (bought floor) future price. We have elected to not designate any of our derivative contracts for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *“(Loss) gain on derivative contracts, net*” on the Consolidated Statements of Operations. All derivative contracts are recorded at fair market value and are included in the Consolidated Balance Sheets as assets or liabilities.

Stock-Based Compensation

The Company recognized stock-based compensation expense associated with restricted stock units, which include both time- and performance-based awards. The Company accounts for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to time-based restricted stock units is based on the price of the Class A common stock, $0.001 par value per share of Earthstone (“Class A Common Stock”), on the grant date and recognized over the vesting period using the straight-line method. The Company classifies grants to be settled in shares as equity awards and awards to be settled in cash a liability awards. The Company accounts for these awards based on a grant date Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes fair value based on the most likely outcome, and is recognized over the vesting period using the straight-line method. The fair value of the liability awards is updated on a quarterly basis.

Income Taxes and Uncertain Tax Positions

We are a U.S. company operating in Texas, as of December 31, 2021, as well as one foreign legal entity, Lynden Corp, which is a Canadian company. Consequently, our tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which our operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary. Therefore, as a part of the process of preparing the consolidated financial statements, we are required to estimate the income taxes in each of these jurisdictions. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year as our operations are conducted in different taxing jurisdictions.

Our corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return resulting from Earthstone's acquisition of Lynden Corp in 2016 (the "Lynden Arrangement") that includes Lynden US, Earthstone, and Lynden Corp. As such, taxable income of Earthstone cannot be offset by tax attributes, including net operating losses, of Lynden US, nor can taxable income of Lynden US be offset by tax attributes of Earthstone. Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

On January 7, 2021, upon closing of the IRM Acquisition, the acquired entity, Independence Resources Management, LLC (along with its wholly owned subsidiaries, collectively "IRM"), became a wholly owned subsidiary of EEH. IRM's results will be reported on the U.S. Return of Partnership Income (Form 1065) and will flow to EEH through Schedule K-1 (Form 1065). As IRM is treated as a Partnership, for federal and state income tax purposes, it is not subject to income taxes at the federal level. At the state level, IRM only operates in Texas and is subject to the Texas Margin Tax.

Our deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported in our Consolidated Balance Sheets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2021 and 2020, we recorded a valuation allowance for our deferred tax assets in the Consolidated Balance Sheets.

On February 15, 2022, as a result of the completion of the Chisholm Acquisition, which included the issuance of 19,417,476 shares of our Class A Common Stock, a limitation was triggered under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"). We are currently assessing the impact of the limitation on both our NOL and our deferred tax asset.

We apply the accounting standards related to uncertainty in income taxes. This accounting guidance clarifies the accounting for uncertainties in income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the consolidated financial statements. It requires that we recognize in the consolidated financial statements the financial effects of a tax position, if that position is more likely than not of being sustained upon examination, including resolution of any appeals or litigation processes, based upon the technical merits of the position. It also provides guidance on measurement, classification, interest, penalties and disclosure. Our tax positions related to our pass-through status and state income tax liability, including deductibility of expenses, have been reviewed by our management and they believe those positions would more likely than not be sustained upon examination. Accordingly, we have not recorded an income tax liability for uncertain tax positions at December 31, 2021 or 2020.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil, natural gas and NGLs. Revenues are recognized when the recognition criteria of FASB ASC Topic 606, *Revenue from Contracts with Customers*, are met, which generally occurs at the point in which title passes to the customers. We receive payment from one to three months after delivery. At the end of each quarter, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, however, differences have been insignificant.

Accounting for Business Combinations

Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair value including the recognition of acquisition-related costs that are separate from the acquired net assets. The purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, and comparison to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Noncontrolling Interest

We account for noncontrolling interest in accordance with FASB ASC Topic 810, *Consolidation*, which requires the recording of a noncontrolling interest component of Net income (loss), as well as a noncontrolling interest component within equity. Noncontrolling interest represents third-party equity ownership of EEH and is presented as a component of equity in the Consolidated Balance Sheet as of December 31, 2021 and 2020, as well as an adjustment to Net income (loss) in the Consolidated Statement of Operations for the years ended December 31, 2021 and 2020.

As of December 31, 2021, Earthstone and Lynden US held 60.9% of the outstanding membership interests in EEH while Bold Holdings, the noncontrolling party, held the remaining 39.1%. See further discussion in *Note 8. Noncontrolling Interest* in the *Notes to Consolidated Financial Statements*.

Recently Issued Accounting Standards

See *Note 2. Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this report for a discussion of recently issued accounting standards affecting us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. We have established risk management processes to monitor and manage these market risks.

Commodity Price Risk, Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil, natural gas and NGL prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable. Our hedging activities consist of derivative instruments entered into in order to hedge against changes in oil and natural gas prices through the use of fixed price swaps, basis swaps and costless collars. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum (sold ceiling) and a minimum (bought floor) future price.

We have entered into a series of derivative instruments to hedge a significant portion of our expected oil and natural gas production through December 31, 2023. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. Although not risk free, we believe these instruments reduce our exposure to oil and natural gas price fluctuations and, thereby, allow us to achieve a more predictable cash flow.

The following is a summary of our open oil and natural gas derivative contracts as of December 31, 2021:

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2022	Crude Oil Swap	2,768,250	$57.69
2022	Crude Oil Basis Swap(1)	3,832,500	$0.51
2022	Natural Gas Swap	5,900,000	$3.20
2022	Natural Gas Basis Swap(2)	9,100,000	$(0.26)
2023	Natural Gas Swap	1,375,000	$3.27

(1) The basis differential price is between WTI Midland Argus Crude and the WTI NYMEX.
(2) The basis differential price is between W. Texas (WAHA) and the Henry Hub NYMEX.

	Costless Collars			
Period	Commodity	Volume (Bbls / MMBtu)	Bought Floor ($/Bbl / $/MMBtu)	Sold Ceiling ($/Bbl / $/MMBtu)
2022	Crude Oil Costless Collar	730,000	$ 60.00	$ 73.73
2023	Crude Oil Costless Collar	365,000	$ 55.00	$ 71.75
2022	Natural Gas Costless Collar	4,037,500	$ 3.43	$ 5.10
2023	Natural Gas Costless Collar	888,000	$ 3.25	$ 5.13

Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net liability position with a fair value of $44.4 million at December 31, 2021. Based on the published commodity futures price curves for the underlying commodity as of December 31, 2021, a 10% increase in per unit commodity prices would cause the total fair value of our commodity derivative financial instruments to decrease by approximately $22.6 million to an overall net liability position of $21.8 million. A 10% decrease in per unit commodity prices would cause the total fair value of our commodity derivative financial instruments to increase by approximately $22.6 million to an overall net liability position of $67.0 million. There would also be a similar increase or decrease in (Loss) gain on derivative contracts, net in the Consolidated Statements of Operations.

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are based on LIBOR and, upon the closing of the Chisholm Acquisition, SOFR, and the prime rate and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At December 31, 2021, the outstanding borrowings under the Credit Agreement were $320.0 million bearing interest at rates described in *Note 12. Long-Term Debt* in the *Notes to Consolidated Financial Statements*. Fluctuations in interest rates will cause our annual interest costs to fluctuate. At December 31, 2021, the interest rate on borrowings under the Credit Agreement was 3.110% per year. If borrowings at December 31, 2021 were to remain constant, a 10% change in interest rates would impact our future cash flows by approximately $1.0 million per year.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2021, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during future periods.

Item 8. Financial Statements and Supplementary Data

See *Index to Consolidated Financial Statements and Supplementary Information* on Page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Internal Control Over Financial Reporting

Evaluation of Disclosure Controls and Procedures

(a) Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Principal Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Principal Accounting Officer, of the effectiveness of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below under paragraph (b) within Management's Annual Report on Internal Control over Financial Reporting, our Chief Executive Officer and Principal Accounting Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Principal Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

The audit report of our independent registered public accounting firm, which is included in this Annual Report on Form 10-K, expressed an unqualified opinion on our consolidated financial statements.

(b) Management's Annual Report on Internal Control over Financial Reporting

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

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

While "reasonable assurance" is a high level of assurance, it does not mean absolute assurance. Because of its inherent limitations, internal control over financial reporting may not prevent or detect every misstatement and instance of fraud. Controls are susceptible to manipulation, especially in instances of fraud caused by collusion of two or more people. 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.

Under the supervision and with the participation of our Chief Executive Officer and Principal Accounting Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2021. In making this evaluation, management used the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the results of our evaluation, our management concluded that our internal control over financial reporting was effective, at the reasonable assurance level, as of December 31, 2021.

Our independent registered public accounting firm that audited our consolidated financial statements, has also issued its own audit report on the effectiveness of our internal control over financial reporting as of December 31, 2021, which is included herein.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of
Earthstone Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited Earthstone Energy, Inc. and subsidiaries (the “Company”) internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework (2013)* 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, 2021, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated balance sheets of Earthstone Energy, Inc. and subsidiaries as of December 31, 2021 and 2020, the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the “consolidated financial statements”) and our report dated March 9, 2022 expressed an unqualified opinion on those.

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 Report on Internal Control over Financial Reporting included in Item 9A. 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/Moss Adams LLP

Houston, Texas
March 9, 2022

We have served as the Company's auditor since 2018.

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

See list of “Information about our Executive Officers” under Item 1 of this report, which is incorporated herein by reference.

The other information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2021.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2021.

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

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2021.

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

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2021.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2021.

PART IV

Item 15. Exhibit and Financial Statement Schedules

Exhibit No.	Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	SEC File No.	Exhibit	Filing Date		
2.1	Contribution Agreement dated November 7, 2016, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, Lynden USA Inc., Lynden USA Operating, LLC, Bold Energy Holdings, LLC and Bold Energy III LLC.	8-K	001-35049	2.1	November 8, 2016		
2.1(a)	First Amendment to the Contribution Agreement dated March 21, 2017, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, Lynden USA Inc., Lynden USA Operating, LLC, Bold Energy Holdings, LLC and Bold Energy III LLC.	8-K	001-35049	2.1	March 23, 2017		
2.2	Purchase and Sale Agreement dated as of December 17, 2020, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, Independence Resources Holdings, LLC and Independence Resources Manager, LLC.	8-K	001-35049	2.1	December 22, 2020		
2.3	Purchase and Sale Agreement dated March 31, 2021, among Tracker Resource Development III, LLC, TRD III Royalty Holdings (TX), LP, Earthstone Energy, Inc. and Earthstone Energy Holdings, LLC.	8-K	001-35049	2.1	April 5, 2021		
2.4	Purchase and Sale Agreement dated March 31, 2021, among SEG-TRD LLC, SEG-TRD II LLC, Earthstone Energy, Inc. and Earthstone Energy Holdings, LLC.	8-K	001-35049	2.2	April 5, 2021		
2.5	Purchase and Sale Agreement dated as of September 30, 2021, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, and Foreland Investments LP.	8-K	001-35049	2.1	October 4, 2021		
2.6	Purchase and Sale Agreement dated as of September 30, 2021, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, and BCC-Foreland LLC.	8-K	001-35049	2.2	October 4, 2021		
2.7	Purchase and Sale Agreement dated December 15, 2021, by and between Chisholm Energy Operating, LLC, Chisholm Energy Agent, Inc., Earthstone Energy, Inc., and Earthstone Energy Holdings, LLC.	8-K	001-35049	2.1	December 17, 2021		
2.8	Purchase and Sale Agreement dated January 30, 2022, by and among Bighorn Asset Company, LLC, Earthstone Energy, Inc. and Earthstone Energy Holdings, LLC.	8-K	001-35049	2.1	February 2, 2022		
3.1	Third Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated May 9, 2017.	8-A	001-35049	3.1	May 9, 2017		
3.1(a)	Certificate of Amendment to the Third Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated July 20, 2021.	8-K	001-35049	3.1	July 23, 2021		

3.2	Amended and Restated Bylaws of Earthstone Energy, Inc. dated February 26, 2010.	8-K	001-35049	3(ii)	March 3, 2010
3.2(a)	First Amendment to the Amended and Restated Bylaws of Earthstone Energy, Inc. dated November 22, 2011.	8-K	001-35049	3(ii)c	November 23, 2011
3.2(b)	Second Amendment to the Amended and Restated Bylaws of Earthstone Energy, Inc. dated October 22, 2015.	8-K	001-35049	3.2	October 26, 2015
4.1	Specimen Class A Common Stock Certificate of Earthstone Energy, Inc.	8-K	001-35049	4.1	May 15, 2017
4.2	Description of Earthstone Energy, Inc.'s Class A Common Stock.	10-K	001-35049	4.2	March 11, 2020
10.1†	Earthstone Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-35049	10.3	December 29, 2014
10.1(a)†	First Amendment to the Earthstone Energy, Inc. 2014 Long-Term Incentive Plan dated October 22, 2015.	8-K	001-35049	10.1	October 26, 2015
10.1(b)†	Second Amendment to the Earthstone Energy, Inc. 2014 Long-Term Incentive Plan dated May 9, 2017.	8-K	001-35049	10.6	May 15, 2017
10.2	Form of Indemnification Agreement.	8-K	001-35049	10.5	December 29, 2014
10.3†	Form of Restricted Stock Unit Agreement (Executive Management).	8-K	001-35049	10.1	June 2, 2016
10.4†	Form of Restricted Stock Unit Agreement (Employee).	8-K	001-35049	10.2	June 2, 2016
10.5	First Amended and Restated Limited Liability Company Agreement of Earthstone Energy Holdings, LLC dated May 9, 2017.	8-K	001-35049	10.1	May 15, 2017
10.6	Registration Rights Agreement dated May 9, 2017 between Earthstone Energy, Inc. and Bold Energy Holdings, LLC.	8-K	001-35049	10.3	May 15, 2017
10.7	Voting Agreement dated May 9, 2017 by and among Earthstone Energy, Inc., EnCap Investments L.P., Oak Valley Resources, LLC and Bold Energy Holdings, LLC.	8-K	001-35049	10.4	May 15, 2017
10.7(a)	First Amendment to the Voting Agreement dated April 22, 2020, by and among Earthstone Energy, Inc., EnCap Investments L.P., and Bold Energy Holdings, LLC.	8-K	001-35049	10.1	April 24, 2020
10.8†	Performance Unit Award Agreement (Executive Management).	8-K	001-35049	10.2	March 2, 2018
10.9†	Amended and Restated 2014 Long Term Incentive Plan dated June 6, 2018.	8-K	001-35049	10.1	June 6, 2018
10.9(a)	First Amendment to the Earthstone Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan dated June 3, 2020.	8-K	001-35049	10.1	June 5, 2020
10.9(b)	Amendment No. 2 to the Earthstone Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan dated July 20, 2021.	8-K	001-35049	10.5	July 23, 2021
10.10†	Form of Performance Unit Agreement (Executive Management).	8-K	001-35049	10.2	February 1, 2019
10.11†	Earthstone Energy, Inc. Amended and Restated Change in Control and Severance Benefit Plan.	8-K	001-35049	10.1	January 29, 2021

10.12	Credit Agreement dated November 21, 2019, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, Wells Fargo Bank, National Association as Administrative Agent and Issuing Bank, BOKF, NA dba Bank of Texas, as Issuing Bank with respect to Existing Letters of Credit, Royal Bank of Canada, as Syndication Agent, SunTrust Bank, as Documentation Agent, and the Lenders party thereto.	8-K	001-35049	10.1	November 22, 2019
10.12(a)	First Amendment to Credit Agreement dated September 28, 2020, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, the Guarantors party thereto, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders party thereto.	8-K	001-35049	10.1	October 1, 2020
10.12(b)	Second Amendment to Credit Agreement dated December 17, 2020, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, the Guarantors party thereto, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders party thereto.	8-K	001-35049	10.1	December 22, 2020
10.12(c)	Third Amendment to Credit Agreement dated as of April 20, 2021, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and guarantors party thereto.	8-K	001-35049	10.1	April 20, 2021
10.12(d)	Fourth Amendment to Credit Agreement dated as of September 17, 2021, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and guarantors party thereto.	8-K	001-35049	10.1	September 20, 2021
10.12(e)	Fifth Amendment to Credit Agreement dated as of December 24, 2021, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and guarantors party thereto.	8-K	001-35049	10.1	December 29, 2021
10.12(f)	Amended and Restated Fifth Amendment to Credit Agreement dated as of January 30, 2022, among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Energy, Inc., as Parent, Wells Fargo Bank, National Association, as Administrative Agent, the lenders and guarantors party thereto.	8-K	001-35049	10.1	February 2, 2022
10.13†	Form of Performance Unit Agreement (Executive Management).	8-K	001-35049	10.1	January 31, 2020
10.14†	Form of Restricted Stock Unit Agreement (Executive Management).	8-K	001-35049	10.2	January 31, 2020
10.15†	Form of Restricted Stock Unit Agreement (Director).	8-K	001-35049	10.3	January 31, 2020

10.16	Registration Rights Agreement dated January 7, 2021, by and among Earthstone Energy, Inc., Independence Resources Holdings, LLC and the Persons identified on Schedule I thereto.	8-K	001-35049	10.1	January 13, 2021
10.17	Voting Agreement dated January 7, 2021, by and among Earthstone Energy, Inc., EnCap Investments L.P., Warburg Pincus Private Equity (E&P) XI – A, L.P., Warburg Pincus XI (E&P) Partners – A, L.P., WP IRH Holdings, L.P., Warburg Pincus XI (E&P) Partners – B IRH, LLC, Warburg Pincus Energy (E&P)-A, LP, Warburg Pincus Energy (E&P) Partners-A, LP, Warburg Pincus Energy (E&P) Partners-B IRH, LLC, WP Energy Partners IRH Holdings, L.P., and WP Energy IRH Holdings, L.P.	8-K	001-35049	10.2	January 13, 2021
10.18	Lock-up Agreement dated January 7, 2021, by and among Earthstone Energy, Inc., Warburg Pincus Private Equity (E&P) XI – A, L.P., Warburg Pincus XI (E&P) Partners – A, L.P., WP IRH Holdings, L.P., Warburg Pincus XI (E&P) Partners – B IRH, LLC, Warburg Pincus Energy (E&P)-A, LP, Warburg Pincus Energy (E&P) Partners-A, LP, Warburg Pincus Energy (E&P) Partners-B IRH, LLC, WP Energy Partners IRH Holdings, L.P., and WP Energy IRH Holdings, L.P.	8-K	001-35049	10.3	January 13, 2021
10.19†	Form of Performance Unit Agreement (Executive Management).	8-K	001-35049	10.1	January 29, 2021
10.20	Support and Voting Agreement dated March 31, 2021, by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC, Tracker Resource Development III, LLC, TRD III Royalty Holdings (TX), LP, SEG-TRD LLC, SEG-TRD II LLC, Warburg Pincus Private Equity (E&P) XI – A, L.P., Warburg Pincus XI (E&P) Partners – A, L.P., WP IRH Holdings, L.P., Warburg Pincus XI (E&P) Partners – B IRH, LLC, Warburg Pincus Energy (E&P)-A, LP, Warburg Pincus Energy (E&P) Partners-A, LP, Warburg Pincus Energy (E&P) Partners-B IRH, LLC, WP Energy Partners IRH Holdings, L.P., and WP Energy IRH Holdings, L.P.	8-K	001-35049	10.1	April 5, 2021
10.21	Registration Rights Agreement dated July 20, 2021, by and among Earthstone Energy, Inc., Tracker Resource Development III, LLC, EnCap Energy Capital Fund VIII, L.P., ZIP Ventures I, L.L.C. and Tracker III Holdings, LLC.	8-K	001-35049	10.1	July 23, 2021
10.22	Registration Rights Agreement dated July 20, 2021, by and among Earthstone Energy, Inc., SEG-TRD LLC, and SEG-TRD II LLC.	8-K	001-35049	10.2	July 23, 2021

10.23	Lock-up Agreement dated July 20, 2021, between Earthstone Energy, Inc. and EnCap Energy Capital Fund VIII, L.P.	8-K	001-35049	10.3	July 23, 2021	
10.24	Lock-up Agreement dated July 20, 2021, between Earthstone Energy, Inc. and ZIP Ventures I, L.L.C.	8-K	001-35049	10.4	July 23, 2021	
10.25	Registration Rights Agreement dated November 2, 2021, by and among Earthstone Energy, Inc., Foreland Investments LP, the parties listed on Schedule I thereto, and the Persons identified on Schedule II thereto.	8-K	001-35049	10.1	November 2, 2021	
10.26	Form of Lock-up Agreement.	8-K	001-35049	10.2	November 2, 2021	
10.27	Securities Purchase Agreement dated as of January 30, 2022, by and among Earthstone Energy, Inc. and the purchasers set forth therein.	8-K	001-35049	10.2	February 2, 2022	
10.28	Registration Rights Agreement dated February 15, 2022 by and among Earthstone Energy, Inc., Chisholm Energy Operating, LLC, and Chisholm Energy Holdings, LLC.	8-K	001-35049	10.1	February 18, 2022	
10.29	Form of Lock-up Agreement.	8-K	001-35049	10.2	February 18, 2022	
10.30	Amended and Restated Voting Agreement dated February 15, 2022, by and among Earthstone Energy, Inc., EnCap Investments L.P., Warburg Pincus Private Equity (E&P) XI – A, L.P., Warburg Pincus XI (E&P) Partners – A, L.P., WP IRH Holdings, L.P., Warburg Pincus XI (E&P) Partners – B IRH, LLC, Warburg Pincus Energy (E&P)-A, LP, Warburg Pincus Energy (E&P) Partners-A, LP, Warburg Pincus Energy (E&P) Partners-B IRH, LLC, WP Energy Partners IRH Holdings, L.P., and WP Energy IRH Holdings, L.P., WP Energy Chisholm Holdings, L.P., WP Energy Partners Chisholm Holdings, L.P., Warburg Pincus Energy (E&P) Partners-B Chisholm, LLC, Warburg Pincus Private Equity (E&P) XII (A), L.P., WP XII Chisholm Holdings, L.P., Warburg Pincus XII (E&P) Partners-2 Chisholm, LLC, Warburg Pincus Private Equity (E&P) XII-D (A), L.P., Warburg Pincus Private Equity (E&P) XII-E (A), L.P., Warburg Pincus XII (E&P) Partners-1, L.P., and WP XII (E&P) Partners (A), L.P.	8-K	001-35049	10.3	February 18, 2022	
14.1	Code of Business Conduct and Ethics.	8-K	001-35049	14	January 13, 2021	
21.1	List of Subsidiaries.					X
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X
23.2	Consent of Moss Adams LLP.					X
31.1	Certification of the Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X
31.2	Certification of the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X

32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act.		X
32.2	Certification of the Executive Vice President - Accounting and Administration pursuant to Section 906 of the Sarbanes-Oxley Act.		X
99.1	Report of Cawley, Gillespie & Associates, Inc.	X	
101.INS	XBRL Instance Document.	X	
101.SCH	XBRL Schema Document.	X	
101.CAL	XBRL Calculation Linkbase Document.	X	
101.DEF	XBRL Definition Linkbase Document.	X	
101.LAB	XBRL Label Linkbase Document.	X	
101.PRE	XBRL Presentation Linkbase Document.	X	
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).	X	
†	Indicates management contract or compensatory plan or arrangement.		

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.

EARTHSTONE ENERGY, INC.

		By:	/s/ Robert J. Anderson
		Name:	Robert J. Anderson
Date:	March 9, 2022	Title:	*President, Chief Executive Officer and Director (Principal Executive 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.

Signature	Title	Date
/s/ Robert J. Anderson Robert J. Anderson	President, Chief Executive Officer and Director (Principal Executive Officer)	March 9, 2022
/s/ Tony Oviedo Tony Oviedo	Executive Vice President, Accounting and Administration (Principal Financial Officer and Principal Accounting Officer)	March 9, 2022
/s/ Frank A. Lodzinski Frank A. Lodzinski	Executive Chairman	March 9, 2022
/s/ David S. Habachy David S. Habachy	Director	March 9, 2022
/s/ Jay F. Joliat Jay F. Joliat	Director	March 9, 2022
/s/ Phil D. Kramer Phil D. Kramer	Director	March 9, 2022
/s/ Ray Singleton Ray Singleton	Director	March 9, 2022
/s/ Wynne M. Snoots, Jr. Wynne M. Snoots, Jr.	Director	March 9, 2022
/s/ Brad A. Thielemann Brad A. Thielemann	Director	March 9, 2022
/s/ Zachary G. Urban Zachary G. Urban	Director	March 9, 2022
/s/ Robert L. Zorich Robert L. Zorich	Director	March 9, 2022

EARTHSTONE ENERGY, INC.
Index to Consolidated Financial Statements and Supplementary Information

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of
Earthstone Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Earthstone Energy, Inc. and subsidiaries (the “Company”) as of December 31, 2021 and 2020, the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2021 and 2020, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 9, 2022 expressed an unqualified opinion on the Company’s internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated 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 consolidated 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 consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the Estimated Proved Oil and Gas Reserves on the Determination of Depreciation, Depletion, and Amortization Expense related to Proved Oil and Natural Gas Properties and Impairment of Proved Oil and Natural Gas Properties

The Company’s net proved oil and natural gas properties balance was $1,235.1 million as of December 31, 2021, and the associated depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2021 was $105.7 million. The Company recorded no impairment expense for the year ended December 31, 2021. As described in Note 7 to the consolidated financial statements, the Company follows the successful efforts method of accounting for its oil and natural gas properties. The Company’s lease acquisition costs and development costs of proved oil and natural gas properties are amortized using the units-of-production method, at the field level, based on total estimated proved oil and natural gas reserves and estimated proved developed oil and natural gas reserves, respectively. Proved oil and natural gas properties are reviewed for impairment on a periodic basis. If impairment is indicated, the impairment charge reduces the carrying values to their estimated fair values. These fair value measurements are classified as Level 3 measurements and include many unobservable inputs. Fair value is calculated as the estimated discounted future net cash flows attributable to the assets. The Company’s primary assumptions in preparing the estimated discounted future net cash flows to be recovered from oil and natural gas properties are based on (i) proved reserves, (ii) forward commodity prices and assumptions as to costs and expenses, and (iii) the estimated discount rate that would be used by potential purchasers to determine the fair value of the assets.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on proved net oil and natural gas properties is a critical audit matter are there was (i) significant judgment by management, including the use of specialists, when developing the fair value measurement of proved oil and natural gas reserves; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating management’s significant assumptions related to developing those estimates, including future production amounts and costs, oil and natural gas prices, future pricing differentials, and future development costs including the Company’s ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking as well as the weighted average cost of capital; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. The procedures we performed to address this critical audit matter included:

(i) Testing the operating effectiveness of internal controls relating to management’s estimates of proved oil and natural gas reserves, the calculation of DD&A expense, and the impairment assessment of proved oil and natural gas properties;
(ii) Evaluating the significant assumptions used by management in developing these estimates, including future production, future and historical oil and gas prices, pricing differentials, and future development costs;
(iii) Evaluating management’s development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company’s drill plan and the availability of capital relative to the drill plan;
(iv) Utilizing the work of management’s specialists to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for this work, the specialists’ qualifications and objectivity were assessed, as well as the reasonableness of methods and assumptions used by the specialists. The procedures performed also included testing the data used by the specialists and evaluating the specialists’ findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support whether the assumptions used were consistent with the past performance of the Company and whether they were consistent with evidence obtained in other areas of the audit;
(v) Testing management’s impairment assessment of proved oil and natural gas properties, including evaluating management’s cash flow analysis related to the proved oil and natural gas properties. In addition, we involved internal valuation professionals with specialized skills and knowledge, who assisted in evaluating the discount rate used in the valuation by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities;
(vi) Testing the inputs of and recalculating management’s DD&A calculation.

Acquisition of Independence Resources Holdings, LLC and Independence Resources Manager, LLC (collectively "IRM") - Valuation of Proved Natural Gas and Oil Properties

As described in Note 3 to the consolidated financial statements, $224.1 million was allocated to proved oil and natural gas properties related to the purchase price of IRM on January 7, 2021. As disclosed by management, the Company accounts for business combinations under the acquisition method of accounting. Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. The fair value estimate of proved oil and natural gas properties as of an acquisition date was based on estimated proved oil and natural gas reserves and related future net cash flows discounted using a weighted average cost of capital, including estimates and assumptions of future commodity prices and costs, the timing of development activities, projections of oil and natural gas reserves, and estimates to abandon and reclaim producing wells. As disclosed by management, the accuracy of the reserve estimates is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs, and other factors. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the allocation and valuation of proved oil and natural gas properties acquired in the IRM acquisition is a critical audit matter are the (i) significant judgment by management, including the use of management's specialists, when developing the fair value measurement of proved natural gas and oil properties; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating management's significant assumptions related to future production volumes and commodity prices, as well as the weighted average cost of capital; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. The primary procedures we performed to address this critical audit matter included:

(i) Testing the operating effectiveness of internal controls relating to the valuation of the acquired proved natural gas and oil properties;
(ii) Testing management's process for developing the fair value measurement of proved natural gas and oil properties;
(iii) Evaluating the appropriateness of the discounted cash flow model, which included testing the completeness and accuracy of underlying data used in the model and evaluating significant assumptions used by management related to future production volumes and commodity prices, as well as the weighted average cost of capital. The evaluation of management's assumption related to future commodity prices involved comparing the prices against observable market data. Professionals with specialized skill and knowledge were used to assist in the evaluation of the weighted average cost of capital assumption and the appropriateness of the discounted cash flow model.
(iv) Evaluating the professional qualifications and objectivity of the Company's engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff.

/s/Moss Adams LLP

Houston, Texas
March 9, 2022

We have served as the Company's auditor since 2018.

EARTHSTONE ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

ASSETS	December 31, 2021	December 31, 2020
Current assets:		
Cash	$ 4,013	$ 1,494
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	50,575	16,255
Joint interest billings and other, net of allowance of $19 and $19 at December 31, 2021 and 2020, respectively	2,930	7,966
Derivative asset	1,348	7,509
Prepaid expenses and other current assets	2,549	1,509
Total current assets	61,415	34,733
Oil and gas properties, successful efforts method:		
Proved properties	1,625,367	1,017,496
Unproved properties	222,025	233,767
Land	5,382	5,382
Total oil and gas properties	1,852,774	1,256,645
Accumulated depreciation, depletion and amortization	(395,625)	(291,213)
Net oil and gas properties	1,457,149	965,432
Other noncurrent assets:		
Office and other equipment, net of accumulated depreciation of $4,547 and $3,675 at December 31, 2021 and 2020, respectively	1,986	931
Derivative asset	157	396
Operating lease right-of-use assets	1,795	2,450
Other noncurrent assets	33,865	1,315
TOTAL ASSETS	$ 1,556,367	$ 1,005,257
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 31,397	$ 6,232
Revenues and royalties payable	36,189	27,492
Accrued expenses	31,704	16,504
Asset retirement obligation	395	447
Derivative liability	45,310	1,135
Advances	4,088	2,277
Operating lease liability	681	773
Finance lease liability	—	69
Other current liabilities	851	565
Total current liabilities	150,615	55,494
Noncurrent liabilities:		
Long-term debt	320,000	115,000
Asset retirement obligation	15,471	2,580
Derivative liability	571	173
Deferred tax liability	15,731	14,497
Operating lease liability	1,276	1,840
Finance lease liability	—	5
Other noncurrent liabilities	6,442	132
Total noncurrent liabilities	359,491	134,227
Commitments and Contingencies (Note 15)		
Equity:		
Preferred stock, $0.001 par value, 20,000,000 shares authorized; none issued or outstanding	—	—
Class A Common Stock, $0.001 par value, 200,000,000 shares authorized; 53,467,307 and 30,343,421 issued and outstanding at December 31, 2021 and 2020, respectively	53	30

Class B Common Stock, $0.001 par value, 50,000,000 shares authorized; 34,344,532 and 35,009,371 issued and outstanding at December 31, 2021 and 2020, respectively	34	35
Additional paid-in capital	718,181	540,074
Accumulated deficit	(159,774)	(195,258)
Total Earthstone Energy, Inc. equity	558,494	344,881
Noncontrolling interest	487,767	470,655
Total equity	1,046,261	815,536
TOTAL LIABILITIES AND EQUITY	$ 1,556,367	$ 1,005,257

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share and per share amounts)

	Years Ended December 31,		
	2021	**2020**	**2019**
REVENUES			
Oil	$ 297,177	$ 120,355	$ 171,925
Natural gas	50,809	8,567	3,913
Natural gas liquids	71,657	15,601	15,424
Total revenues	419,643	144,523	191,262
OPERATING COSTS AND EXPENSES			
Lease operating expense	49,321	29,131	28,683
Production and ad valorem taxes	26,409	9,411	11,871
Rig idle and termination expense	—	426	—
Impairment expense	—	64,498	—
Depreciation, depletion and amortization	106,367	96,414	69,243
General and administrative expense	41,922	28,233	27,611
Transaction costs	4,875	622	1,077
Accretion of asset retirement obligation	1,065	307	214
Exploration expense	341	298	653
Total operating costs and expenses	230,300	229,340	139,352
Gain on sale of oil and gas properties, net	738	204	3,222
Income (loss) from operations	**190,081**	**(84,613)**	**55,132**
OTHER INCOME (EXPENSE)			
Interest expense, net	(10,796)	(5,232)	(6,566)
Write-off of deferred financing costs	—	—	(1,242)
(Loss) gain on derivative contracts, net	(116,761)	59,899	(43,983)
Other income (expense), net	841	400	(96)
Total other (expense) income	(126,716)	55,067	(51,887)
Income (loss) before income taxes	63,365	(29,546)	3,245
Income tax (expense) benefit	(1,859)	112	(1,665)
Net income (loss)	61,506	(29,434)	1,580
Less: Net income (loss) attributable to noncontrolling interest	26,022	(15,887)	861
Net income (loss) attributable to Earthstone Energy, Inc.	$ 35,484	$ (13,547)	$ 719
Net income (loss) per common share attributable to Earthstone Energy, Inc.:			
Basic	$ 0.75	$ (0.45)	$ 0.02
Diluted	$ 0.71	$ (0.45)	$ 0.02
Weighted average common shares outstanding:			
Basic	47,169,948	29,911,625	28,983,354
Diluted	49,952,093	29,911,625	29,360,885

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands, except share amounts)

	Issued Shares								
	Class A Common Stock	**Class B Common Stock**	**Class A Common Stock**	**Class B Common Stock**	**Additional Paid-in Capital**	**Accumulated Deficit**	**Earthstone Energy, Inc. Equity**	**Noncontrolling Interest**	**Total Equity**
At January 1, 2019	28,696,321	35,452,178	$ 29	$ 35	$ 517,073	$ (182,497)	$ 334,640	$ 491,852	$ 826,492
ASC 842 implementation	—	—	—	—	—	67	67	99	166
Stock-based compensation expense	—	—	—	—	8,648	—	8,648	—	8,648
Vesting of restricted stock units, net of taxes paid	533,312	—	—	—	—	—	—	—	—
Vested restricted stock units retained by the Company in exchange for payment of recipient mandatory tax withholdings	203,394	—	—	—	(1,135)	—	(1,135)	—	(1,135)
Cancellation of treasury shares	(203,394)	—	—	—	—	—	—	—	—
Class B Common Stock converted to Class A Common Stock	191,498	(191,498)	—	—	2,660	—	2,660	(2,660)	—
Net income	—	—	—	—	—	719	719	861	1,580
At December 31, 2019	29,421,131	35,260,680	$ 29	$ 35	$ 527,246	$ (181,711)	$ 345,599	$ 490,152	$ 835,751
Stock-based compensation expense	—	—	—	—	10,054	—	10,054	—	10,054
Vesting of restricted stock units, net of taxes paid	670,981	—	1	—	(1)	—	—	—	—
Vested restricted stock units retained by the Company in exchange for payment of recipient mandatory tax withholdings	243,924	—	—	—	(835)	—	(835)	—	(835)
Cancellation of treasury shares	(243,924)	—	—	—	—	—	—	—	—
Class B Common Stock converted to Class A Common Stock	251,309	(251,309)	—	—	3,610	—	3,610	(3,610)	—
Net loss	—	—	—	—	—	(13,547)	(13,547)	(15,887)	(29,434)
At December 31, 2020	30,343,421	35,009,371	$ 30	$ 35	$ 540,074	$ (195,258)	$ 344,881	$ 470,655	$ 815,536
Stock-based compensation expense	—	—	—	—	9,132	—	9,132	—	9,132
Modification of performance units	—	—	—	—	(2,276)	—	(2,276)	—	(2,276)
Shares issued in connection with IRM Acquisition	12,719,594	—	13	—	76,559	—	76,572	—	76,572
Shares issued in connection with Tracker Acquisition	6,200,000	—	6	—	61,808	—	61,814	—	61,814
Shares issued in connection with Foreland Acquisition	2,611,111	—	2	—	28,119	—	28,121	—	28,121
Vesting of restricted stock units, net of taxes paid	928,342	—	1	—	(1)	—	—	—	—
Class A Shares retained by the Company in exchange for payment of recipient mandatory tax withholdings	453,483	—	—	—	(4,144)	—	(4,144)	—	(4,144)
Cancellation of treasury shares	(453,483)	—	—	—	—	—	—	—	—
Class B Common Stock converted to Class A Common Stock	664,839	(664,839)	1	(1)	8,910	—	8,910	(8,910)	—
Net income	—	—	—	—	—	35,484	35,484	26,022	61,506
At December 31, 2021	53,467,307	34,344,532	$ 53	$ 34	$ 718,181	$ (159,774)	$ 558,494	$ 487,767	$ 1,046,261

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

EARTHSTONE ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2021	2020	2019
Cash flows from operating activities:			
Net income (loss)	$ 61,506	$ (29,434)	$ 1,580
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairment of proved and unproved oil and gas properties	—	46,878	—
Depreciation, depletion and amortization	106,367	96,414	69,243
Accretion of asset retirement obligations	1,065	307	214
Impairment of goodwill	—	17,620	—
Gain on sale of oil and gas properties, net	(738)	(204)	(3,222)
Gain on sale of office and other equipment	(140)	—	—
Settlement of asset retirement obligations	(185)	(195)	(374)
Total loss (gain) on derivative contracts, net	116,761	(59,899)	43,983
Operating portion of net cash received in settlement of derivative contracts	(75,966)	56,044	15,866
Stock-based compensation	21,014	10,054	8,648
Deferred income taxes	1,859	(657)	1,665
Write-off of deferred financing costs	—	—	1,242
Amortization of deferred financing costs	856	322	412
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(19,061)	11,914	(18,035)
(Increase) decrease in prepaid expenses and other current assets	58	(203)	66
Increase (decrease) in accounts payable and accrued expenses	9,293	481	(10,438)
Increase (decrease) in revenues and royalties payable	5,985	(8,323)	7,067
Increase (decrease) in advances	2,200	(9,617)	8,331
Net cash provided by operating activities	230,874	131,502	126,248
Cash flows from investing activities:			
Acquisition of oil and gas properties	(311,324)	—	—
Additions to oil and gas properties	(114,521)	(88,097)	(204,268)
Additions to office and other equipment	(1,365)	(114)	(527)
Proceeds from sale of oil and gas properties	975	414	4,184
Net cash used in investing activities	(426,235)	(87,797)	(200,611)
Cash flows from financing activities:			
Proceeds from borrowings	744,132	136,056	234,680
Repayments of borrowings	(539,132)	(191,056)	(143,508)
Cash paid related to the exchange and cancellation of Class A Common Stock	(4,144)	(836)	(1,135)
Cash paid for finance leases	(70)	(130)	(392)
Deferred financing costs	(2,906)	(67)	(1,836)
Net cash (used in) provided by financing activities	197,880	(56,033)	87,809
Net increase (decrease) in cash	2,519	(12,328)	13,446
Cash at beginning of period	1,494	13,822	376
Cash at end of period	$ 4,013	$ 1,494	$ 13,822
Supplemental disclosure of cash flow information			
Cash paid for:			
Interest	$ 9,648	$ 4,588	$ 6,405
Income taxes	$ 325	$ —	$ —
Non-cash investing and financing activities:			
Class A Common Stock issued in IRM Acquisition	$ 76,572	$ —	$ —
Class A Common Stock issued in Tracker/Sequel Acquisition	$ 61,814	$ —	$ —
Class A Common Stock issued in Foreland Acquisition	$ 28,121	$ —	$ —
Accrued capital expenditures	$ 23,558	$ 7,328	$ 28,356
Lease asset additions - ASC 842	$ —	$ —	$ 3,722
Asset retirement obligations	$ 2,178	$ 762	$ 105

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

EARTHSTONE ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. – Organization and Basis of Presentation

Earthstone Energy, Inc., a Delaware corporation ("Earthstone" and together with its consolidated subsidiaries, the "Company"), is a growth-oriented independent oil and natural gas development and production company. In addition, the Company is active in corporate mergers and the acquisition of oil and natural gas properties that have production and future development opportunities. The Company's operations are all in the up-stream segment of the oil and natural gas industry and all its properties are onshore in the United States.

Earthstone is the sole managing member of Earthstone Energy Holdings, LLC, a Delaware limited liability company (together with its wholly-owned consolidated subsidiaries, "EEH"), with a controlling interest in EEH. Earthstone, together with its wholly-owned subsidiary, Lynden Energy Corp., a corporation organized under the laws of British Columbia ("Lynden Corp"), and Lynden Corp's wholly-owned consolidated subsidiary, Lynden USA Inc., a Utah corporation ("Lynden US") and also a member of EEH, consolidates the financial results of EEH and records a noncontrolling interest in the Consolidated Financial Statements representing the economic interests of EEH's members other than Earthstone and Lynden US.

Note 2. – Summary of Significant Accounting Policies

Principles of Consolidation

The Consolidated Financial Statements include the accounts and balances of the Company and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). All intercompany accounts and transactions, including revenues and expenses, are eliminated in consolidation.

Use of Estimates

The preparation of the Company's Consolidated Financial Statements in conformity with GAAP requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods then ended.

Estimated quantities of crude oil, natural gas and natural gas liquids reserves are the most significant of the Company's estimates. All reserve data used in the preparation of the Consolidated Financial Statements, as well as included in *Note 21. Supplemental Information On Oil And Gas Exploration And Production Activities (Unaudited)*, are based on estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and natural gas liquids. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and natural gas liquids reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil, natural gas and natural gas liquids that are ultimately recovered.

Other items subject to estimates and assumptions include, but are not limited to, the carrying amounts of property, plant and equipment, goodwill, asset retirement obligations, valuation allowances for deferred income tax assets, valuation of derivative instruments and valuation of certain performance-based restricted stock unit awards. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. See *Note 21. Supplemental Information On Oil and Gas Exploration and Production Activities (Unaudited)*.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Accounts Receivable

Accounts receivable include estimated amounts due from crude oil, natural gas, and natural gas liquids purchasers, other operators for which the Company holds an interest, and from non-operating working interest owners. Accrued crude oil, natural gas, and natural gas liquids sales from purchasers and operators consist of accrued revenues due under normal trade terms, generally requiring payment within 60 days of production. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance.

Provisions for bad debts and recoveries on accounts previously charged off are added to the allowance. The Company routinely assesses the recoverability of all material trade receivables and other receivables to determine their collectability. Allowance for uncollectible accounts receivable was $0.02 million and $0.02 million at December 31, 2021 and 2020, respectively.

Derivative Instruments

The Company utilizes derivative instruments in order to manage exposure to risks associated with fluctuating commodity prices and interest rates. The Company recognizes all derivatives as either assets or liabilities, measured at fair value, and recognizes changes in the fair value of derivatives in current earnings. The Company has elected to not designate any of its positions under the hedge accounting rules. Accordingly, these derivative contracts are mark-to-market and any changes in the estimated values of derivative contracts held at the balance sheet date are recognized in (Loss) gain on derivative contracts, net in the Consolidated Statements of Operations as unrealized gains or losses on derivative contracts. Realized gains or losses on derivative contracts are also recognized in (Loss) gain on derivative contracts, net in the Consolidated Statements of Operations.

Oil and Natural Gas Properties

The method of accounting for oil and natural gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. The Company uses the successful efforts method of accounting for oil and natural gas properties. For more information see *Note 7. Oil and Natural Gas Properties*.

Goodwill

Goodwill represents the excess of the purchase price of assets acquired over the fair value of those assets and is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors. The Company had no goodwill recorded in the Consolidated Balance Sheets at December 31, 2021 or 2020.

There were no impairments to Goodwill recorded in the year ended December 31, 2021. A discounted future cash flow analysis of the properties to which the Goodwill was associated was performed based on commodity price futures as of March 31, 2020. The resulting fair value was lower than the net book value of the associated properties. Additionally, the Company’s enterprise value, calculated as the combined market capitalization of the Company’s equity and long-term debt, was lower than the book value of its assets, without allocating between the Company's two major properties, Midland properties and Eagle Ford properties. Accordingly, the entire $17.6 million balance of Goodwill was impaired on that date, resulting in no remaining amounts subject to impairment. There were no impairments to Goodwill recorded in the year ended December 31, 2019.

Office and Other Equipment

Office and other equipment primarily includes leasehold improvements, vehicles, computer equipment and software, office furniture and fixtures and field equipment. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two years to 10 years. The Company had office and other equipment of $2.0 million and $0.9 million, net of accumulated depreciation and amortization of $4.5 million and $3.7 million, at December 31, 2021 and 2020, respectively. During the years ended December 31, 2021, 2020 and 2019, the Company recognized depreciation expense of $0.7 million, $0.5 million and $0.7 million, respectively. See separate finance lease disclosures in *Note 18. Leases*.

Noncontrolling Interest

Noncontrolling Interest represents third-party equity ownership of EEH and is presented as a component of equity in the Consolidated Balance Sheets as of December 31, 2021 and 2020, as well as an adjustment to Net income in the Consolidated Statements of Operations for the years ended December 31, 2021 and 2020. As of December 31, 2021, Earthstone and Lynden US owned a 60.9% membership interest in EEH while Bold Energy Holdings, LLC (“Bold Holdings”), the noncontrolling third-party, owned the remaining 39.1%. See further discussion in *Note 8. Noncontrolling Interest*.

Segment Reporting

Operating segments are components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on the Company's organization and management, it has only one reportable operating segment, which is oil and natural gas exploration and production.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Asset Retirement Obligations

Asset retirement obligations associated with the retirement of long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the asset, including the asset retirement cost, is depreciated over the useful life of the asset. Asset retirement obligations are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligations and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. For further discussion, see *Note 13. Asset Retirement Obligations*.

Business Combinations

The Company accounts for its acquisitions of oil and gas properties not commonly controlled in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, Business Combinations, which, among other things, requires the Company to determine if an asset or a business has been acquired. If the Company determines an asset(s) has been acquired, the asset(s) acquired, as well as any liabilities assumed, are measured and recorded at the acquisition date cost. If the Company determines a business has been acquired, the assets acquired and liabilities assumed are measured and recorded at their fair values as of the acquisition date, recording goodwill for amounts paid in excess of fair value.

Revenue Recognition

The Company's revenues are comprised solely of revenues from customers and include the sale of oil, natural gas and natural gas liquids. The Company believes that the disaggregation of revenue into these three major product types, as presented in the Consolidated Statements of Operations, appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on its single geographic region. Revenues are recognized when the recognition criteria of ASC 606 "Revenue from Contracts with Customers," ("ASC 606") are met, which generally occurs at a point in time when production is sold to a purchaser at a determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. The Company fulfills its performance obligations under its customer contracts through delivery of oil, natural gas and natural gas liquids and revenues are recorded on a monthly basis and the Company receives payment from one to three months after delivery. Generally, each unit of product represents a separate performance obligation. The prices received for oil, natural gas and natural gas liquids sales under the Company's contracts are generally derived from stated market prices which are then adjusted to reflect deductions including transportation, fractionation and processing. As a result, revenues from the sale of oil, natural gas and natural gas liquids will decrease if market prices decline. The sales of oil, natural gas and natural gas liquids, as presented on the Consolidated Statements of Operations, represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil, natural gas and natural gas liquids on behalf of royalty or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Variances between the Company's estimated revenue and actual payment are recorded in the month the payment is received. Historically, however, differences have been insignificant.

At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are recorded in "Accounts receivable: oil, natural gas, and natural gas liquids revenues" in the Consolidated Balance Sheets. As of December 31, 2021 and 2020, amounts receivable from contracts with customers were \$50.6 million and \$16.3 million, respectively. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues in the Consolidated Statements of Operations.

Oil Sales

Oil production is transported from the wellhead to tank batteries or delivery points through flow-lines or gathering systems. Purchasers of the oil take delivery at (i) the tank batteries and transport the oil by truck, or (ii) at a pipeline delivery point and the Company collects a market price, net of pricing differentials. Revenue is recognized when control transfers to the purchaser at the net price received by the Company. Starting in October 2019, certain of the Company's oil sales activity involves buy/sell arrangements that effect a change in location with required repurchase of oil at a delivery point. Because the Company acts as the agent in these transactions, the buy/sell activity is recorded on a net basis and the residual transportation fee is included in Lease operating expenses in the Consolidated Statements of Operations.

Natural Gas and NGL Sales

Under the Company's natural gas sales arrangements, the purchaser takes control of wet gas at a delivery point near the wellhead or at the inlet of the purchaser's processing facility. The purchaser gathers and processes the wet gas and remits proceeds to the Company for the resulting natural gas and NGL sales. Based on the nature of these arrangements, the Company is the agent and the purchaser is the Company's customer, thus, the Company recognizes natural gas and NGL sales based on the net amount of proceeds received from the purchaser.

Imbalances

The Company recognizes revenue for all oil, natural gas and NGL sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil, NGL and natural gas reserves. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company had no imbalances as of December 31, 2021 or 2020.

Contract Balances

Under the Company's product sales contracts, the Company invoices customers once performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Transaction Price Allocated to Remaining Performance Obligations

Substantially all of the Company's product sales are short-term in nature, with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASC 606 which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606 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 contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month that product is delivered to the purchaser. Settlement statements for certain natural gas and NGLs sales, however, may not be received for 30 to 90 days after the date the product is delivered, and as a result the Company is required to estimate the amount of product delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the years ended December 31, 2021 and 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Concentration of Credit Risk

Credit risk represents the actual or perceived financial loss that the Company would record if its purchasers, operators, or counterparties failed to perform pursuant to contractual terms.

The purchasers of the Company's oil, natural gas, and natural gas liquids production consist primarily of independent marketers, major oil and natural gas companies and natural gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts. In the year ended December 31, 2021, two purchasers accounted for 34% and 13%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In the year ended December 31, 2020, three purchasers accounted for 32%, 15% and 12%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In the year ended December 31, 2019, three purchasers accounted for 30%, 14% and 12%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. No other purchaser accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids revenues during the years ended December 31, 2021, 2020 or 2019. Additionally, at December 31, 2021, three purchasers accounted for 26%, 21% and 12%, respectively, of the Company's oil, natural gas and natural gas liquids receivables. At December 31, 2020, three purchasers accounted for 18%, 17% and 16%, respectively, of the Company's oil, natural gas, and natural gas liquids receivables. No other purchaser accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids receivables at December 31, 2021 and 2020.

The Company holds working interests in oil and natural gas properties for which a third-party serves as operator. The operator sells the oil, natural gas, and NGLs to the purchaser, collects the cash, and distributes the cash to the Company. In the year ended December 31, 2021, one operator distributed 13% of the Company's oil, natural gas and natural gas liquids revenues. In the year ended December 31, 2020 one operator distributed 15% of the Company's oil, natural gas and natural gas liquids revenues. In the year ended December 31, 2019, no operator distributed 10% or more of the Company's oil, natural gas and natural gas liquids revenues.

The derivative instruments of the Company are with a small number of counterparties and, from time-to-time, may represent material assets in the Consolidated Balance Sheets. At December 31, 2021, the Company had a net derivative liability position of $44.4 million. At December 31, 2020, the Company had $6.6 million of derivative contracts that were in a material asset position.

The Company regularly maintains its cash in bank deposit accounts. Balances held by the Company at its banks typically exceed Federal Deposit Insurance Corporation ("FDIC") insurance coverage and, as a result, there is a concentration of credit risk related to the amounts of deposit in excess of FDIC insurance coverage.

Stock-Based Compensation

The Company recognized stock-based compensation expense associated with restricted stock units, which include both time- and performance-based awards. The Company accounts for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to time-based restricted stock units is based on the price of the Class A common stock, $0.001 par value per share of Earthstone ("Class A Common Stock"), on the grant date and recognized over the vesting period using the straight-line method. The Company classifies grants to be settled in shares as equity awards and awards to be settled in cash a liability awards. The Company accounts for these awards based on a grant date Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes fair value based on the most likely outcome, and is recognized over the vesting period using the straight-line method. The fair value of the liability awards is updated on a quarterly basis. See *Note 11. Stock-Based Compensation* for further details.

Income Taxes

The Company is a U.S. company operating in Texas, as of December 31, 2021, and includes one foreign legal entity, Lynden Corp, which is a Canadian company. Consequently, the Company's tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which its operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary. Therefore, as a part of the process of preparing the Consolidated Financial Statements, the Company is required to estimate the income taxes in each of these jurisdictions. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes. The Company's effective tax rate for financial statement purposes will continue to fluctuate from year to year as its operations are conducted in different taxing jurisdictions.

The Company records an income tax provision consistent with its status as a corporation. The Company's corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return resulting from Earthstone's acquisition of Lynden Corp in May 2016 (the "Lynden Arrangement") that includes Lynden US, Earthstone, and Lynden Corp. As such, taxable income of Earthstone cannot be offset by tax attributes, including net operating losses, of Lynden US, nor can taxable income of Lynden US be offset by tax attributes of Earthstone. Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the noncontrolling interest, as well as any standalone income or loss generated by each company. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

The Company's deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported in the Consolidated Balance Sheets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2021 and 2020, the Company has recorded a valuation allowance for its deferred tax assets in the Consolidated Balance Sheets.

The Company applies the accounting standards related to uncertainty in income taxes. This accounting guidance clarifies the accounting for uncertainties in income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the Consolidated Financial Statements. It requires that the Company recognize in the Consolidated Financial Statements the financial effects of a tax position, if that position is more likely than not of being sustained upon examination, including resolution of any appeals or litigation processes, based upon the technical merits of the position. It also provides guidance on measurement, classification, interest, penalties and disclosure. The Company's tax positions related to its pass-through status and state income tax liability, including deductibility of expenses, have been reviewed by the Company's management and they believe those positions would more likely than not be sustained upon examination. Accordingly, the Company has not recorded an income tax liability for uncertain tax positions at December 31, 2021 or 2020.

Recently Issued Accounting Standards

Income Taxes - In December 2019, the FASB issued an update that simplifies the accounting for income taxes by removing certain exceptions to the general principles in Topic 740. The amendments also improve consistent application of and simplify GAAP for other areas of Topic 740 by clarifying and amending existing guidance. The amendments in this update are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020 and early adoption is permitted. The Company adopted the update effective January 1, 2021 and the impact was not material to the Consolidated Financial Statements.

Reference Rate Reform - In March 2020, the FASB issued an update that provides optional guidance for a limited period of time to ease the transition from LIBOR to an alternative reference rate. The ASU intends to address certain concerns relating to accounting for contract modifications and hedge accounting. These optional expedients and exceptions to applying GAAP, assuming certain criteria are met, are allowed through December 31, 2022. The Company is currently evaluating the provisions of this update and has not yet determined whether it will elect the optional expedients. The Company does not expect the transition to an alternative rate to have a material impact on its business, operations or liquidity.

Note 3. Acquisitions and Divestitures

The initial accounting for acquisitions and divestitures may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as additional information is obtained about the facts and circumstances that existed as of the acquisition dates.

IRM Acquisition

As part of the execution of its growth strategy to further increase its scale, on January 7, 2021, the Company completed the acquisition (the "IRM Acquisition") of all of the issued and outstanding limited liability company interests in Independence Resources Management, LLC ("IRM") and certain wholly owned subsidiaries for consideration consisting of (i) net cash of approximately $140.5 million and (ii) 12,719,594 shares of Class A Common Stock. The fair value of each share of Class A Common Stock was determined using the closing price of $6.02 per share on January 7, 2021. The purchase agreement contained customary representations and warranties for transactions of this nature. The Company obtained representation and warranty insurance to provide coverage in the event of certain breaches of representations and warranties of the seller contained in the purchase agreement, which are subject to various exclusions, deductibles and other terms and conditions set forth therein.

The IRM Acquisition was accounted for as a business combination using the acquisition method of accounting, with Earthstone identified as the acquirer. The consideration transferred, fair value of assets acquired and liabilities assumed by Earthstone were recorded as follows (in thousands, except share amounts and stock price):

Consideration:		
Shares of Class A Common Stock issued		12,719,594
Class A Common Stock price as of January 7, 2021	$	6.02
Class A Common Stock consideration		76,572
Cash consideration		140,507
Total consideration transferred	**$**	**217,079**
Fair value of assets acquired:		
Cash	$	4,763
Other current assets		11,524
Oil and gas properties		224,112
Other non-current assets		252
Amount attributable to assets acquired	$	240,651
Fair value of liabilities assumed:		
Derivative liability	$	10,177
Other current liabilities		5,196
Asset retirement obligation - noncurrent		8,199
Amount attributable to liabilities assumed	$	23,572

Tracker/Sequel Acquisitions

On March 31, 2021, Earthstone, EEH, Tracker Resource Development III, LLC, a Delaware limited liability company (“Tracker Opco”), and TRD III Royalty Holdings (TX), LP, a Delaware limited partnership (“RoyaltyCo” and collectively with Tracker Opco, “Tracker”), entered into a purchase and sale agreement (the “Tracker Agreement”), which provided that EEH would acquire (the “Tracker Acquisition”) interests in oil and gas leases and related property of Tracker located in Irion County, Texas (the “Tracker Assets”). Also on March 31, 2021, Earthstone, EEH, SEG-TRD LLC, a Delaware limited liability company (“SEG-I”), and SEG-TRD II LLC, a Delaware limited liability company (“SEG-II” and collectively with SEG-I, “Sequel”) entered into a purchase and sale agreement (the “Sequel Agreement” and collectively with the Tracker Agreement, the “Tracker/Sequel Purchase Agreements”), which provided that EEH would acquire (the “Sequel Acquisition” and collectively with the Tracker Acquisition, the “Tracker/Sequel Acquisitions”) certain well-bore interests and related equipment (the “Sequel Assets”).

On July 20, 2021, Earthstone, EEH and Tracker consummated the transactions contemplated in the Tracker Agreement. At the closing of the Tracker Agreement, among other things, EEH acquired the Tracker Assets for aggregate consideration consisting of: (i) $18.8 million in cash, net of customary purchase price adjustments, and (ii) 4.7 million shares of Class A Common Stock. Also, on July 20, 2021, Earthstone, EEH and Sequel consummated the transactions contemplated in the Sequel Agreement. At the closing of the Sequel Agreement, among other things, EEH acquired the Sequel Assets for aggregate consideration consisting of: (i) $41.4 million in cash, net of customary purchase price adjustments, and (ii) 1.5 million shares of Class A Common Stock. The Significant Shareholder, as described in the Note referenced below, owned approximately 49% of Tracker as of the closing of the Tracker Acquisition. See *Note 14. Related Party Transactions* for further discussion.

In accordance with ASC Topic 805, Business Combinations (referred to as “ASC 805”), the Tracker/Sequel Acquisitions have been accounted for as asset acquisitions. The preliminary allocation of the total purchase price in the Tracker/Sequel Acquisitions is based upon management’s estimates of and assumptions related to the relative fair value of assets acquired and liabilities assumed. Although the purchase price allocation is substantially complete as of the date of this filing, there may be further adjustments to the acquired oil and natural gas properties. These amounts will be finalized no later than one year from the acquisition date. The consideration transferred, fair value of assets acquired and liabilities assumed by Earthstone were recorded as follows (in thousands, except share amounts and stock price):

		Total
Consideration:		
Shares of Earthstone Class A Common Stock issued		6,200,000
Earthstone Class A Common Stock price as of July 20, 2021	$	9.97
Class A Common Stock consideration		61,814
Cash consideration (1)		60,159
Direct transaction costs (2)		1,579
Total consideration transferred	$	123,552
Fair value of assets acquired:		
Oil and gas properties	$	124,152
Amount attributable to assets acquired	$	124,152
Fair value of liabilities assumed:		
Noncurrent liabilities - ARO		600
Amount attributable to liabilities assumed	$	600

(1) Includes customary purchase price adjustments.
(2) Represents $1.6 million of transaction costs associated with the Tracker Acquisition and the Sequel Acquisition that have been capitalized in accordance with ASC 805-50.

The following unaudited supplemental pro forma condensed results of operations present consolidated information as though the IRM Acquisition and Tracker/Sequel Acquisitions had been completed as of January 1, 2020. The unaudited supplemental pro forma financial information was derived from the historical consolidated and combined statements of operations for IRM, Tracker, Sequel and Earthstone and adjusted to include depletion expense applied to the adjusted basis of the properties acquired. These unaudited supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the Company for the periods presented or that may be achieved by the Company in the future. Future results may vary significantly from the results reflected in this unaudited pro forma financial information (in thousands, except per share amounts):

	Years Ended December 31,			
		2021		2020
Revenue	$	460,948	$	287,359
Income (loss) before taxes		88,917		(239,752)
Net income (loss)		87,058		(239,980)
Less: Net income (loss) attributable to noncontrolling interest		36,833		(99,695)
Net income (loss) attributable to Earthstone Energy, Inc.		50,226		(140,285)
Pro forma net income (loss) per common share attributable to Earthstone Energy, Inc.:				
Basic	$	1.06	$	(2.87)
Diluted	$	1.01	$	(2.87)

The Company has included in its Consolidated Statements of Operations, revenues of $95.1 million and operating expenses of $44.4 million for the period from January 7, 2021 to December 31, 2021 related to the IRM Acquisition. During the year ended December 31, 2021, the Company recorded $4.0 million of legal and professional fees, and employee severance costs related to the IRM Acquisition which are included in Transaction costs in the Consolidated Statements of Operations.

Additionally, the Company has included in its Consolidated Statements of Operations, revenues of $40.5 million and operating expenses of $11.5 million for the period July 20, 2021 to December 31, 2021 related to the Tracker/Sequel Acquisitions.

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation.

Significant inputs to the valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future plugging and abandonment costs, (v) estimated future cash flows, and (vi) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates and are the most sensitive and subject to change.

Eagle Ford Acquisitions

In May and June 2021, the Company completed acquisitions of working interests in certain assets it operates located in southern Gonzales County, Texas (collectively, the "Eagle Ford Acquisitions") from four separate sellers. The aggregate purchase price of the Eagle Ford Acquisitions was approximately $45.2 million. One of the four separate sellers was a related party. See *Note 14. Related Party Transactions* for further discussion. The Eagle Ford Acquisitions have been accounted for as asset acquisitions in accordance with ASC 805. The preliminary allocation of each purchase was based upon management's estimates of and assumptions related to the relative fair value of assets acquired and liabilities assumed. Although the purchase price allocation is substantially complete as of the date of this filing, there may be further adjustments to the acquired oil and natural gas properties. These amounts will be finalized no later than one year from the acquisition date.

Foreland-BCC Acquisition

On November 2, 2021, Earthstone, EEH and Foreland Investments LP, a Delaware limited partnership ("Foreland"), consummated the transactions contemplated in the Purchase and Sale Agreement dated as of September 30, 2021 by and among Earthstone, EEH and Foreland (the "Foreland Purchase Agreement"). At the closing of the Foreland Purchase Agreement, EEH acquired (the "Foreland Acquisition") interests in oil and gas leases and related property of Foreland located in Irion County and Crockett County, Texas, for a purchase price consisting of: (i) $16.3 million in cash, net of customary purchase price adjustments, and (ii) 2,611,111 shares of Class A Common Stock.

Also, on November 2, 2021, Earthstone, EEH and BCC-Foreland LLC, a Delaware limited liability company ("BCC"), consummated the transactions contemplated in the Purchase and Sale Agreement dated as of September 30, 2021 by and among Earthstone, EEH and BCC (the "BCC Purchase Agreement"). At the closing of the BCC Purchase Agreement, EEH acquired (the "BCC Acquisition" and with the Foreland Acquisition, the "Foreland-BCC Acquisition") certain well-bore interests and related equipment held by BCC that were part of a joint development agreement between Foreland, Foreland Operating, LLC, and BCC involving portions of the acreage covered by the Foreland Purchase Agreement for a purchase price of $23.0 million in cash, net of customary purchase price adjustments.

Divestitures

There were no material divestitures during the years ended December 31, 2021 or 2020. During the year ended December 31, 2019, the Company sold certain non-core properties for approximately $4.2 million in cash, resulting in a gain of approximately $3.6 million recorded in Gain on sale of oil and gas properties, net in the Consolidated Statements of Operations.

Note 4. Transaction Costs

During the year ended December 31, 2021, the Company recorded transaction costs primarily due to legal, consulting and other fees of approximately $4.0 million related to the IRM Acquisition, $1.8 million related to the Chisholm Acquisition and $0.3 million related to other potential transactions, offset by net reimbursements of $1.2 million related to the business combination (the "Bold Transaction") pursuant to the Bold Contribution Agreement (as defined below) which closed on May 9, 2017.

During the year ended December 31, 2020, the Company recorded transaction costs primarily due to legal, consulting and other fees of approximately $1.0 million related to the acquisition noted above and $0.3 million related to other potential transactions, offset by net reimbursements of $0.7 million related to the Bold Transaction.

During the year ended December 31, 2019, the Company recorded transaction costs totaling approximately $1.1 million primarily due to the Bold Transaction.

Note 5. Fair Value Measurements

FASB ASC Topic 820, defines fair value as the price that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. ASC Topic 820 provides a framework for measuring fair value, establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date and requires consideration of the counterparty's creditworthiness when valuing certain assets.

The three-level fair value hierarchy for disclosure of fair value measurements defined by ASC Topic 820 is as follows:

Level 1 – Unadjusted, quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is defined as a market where transactions for the financial instrument occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs, other than quoted prices within Level 1, that are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3 – Prices or valuations that require unobservable inputs that are both significant to the fair value measurement and unobservable. Valuation under Level 3 generally involves a significant degree of judgment from management.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instrument's complexity. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level. There were no transfers between fair value hierarchy levels for the year ended December 31, 2021.

Fair Value on a Recurring Basis

Derivative Financial Instruments

Derivative financial instruments are carried at fair value and measured on a recurring basis. The derivative financial instruments consist of fixed price swaps, basis swaps and costless collars for crude oil and natural gas and interest rate swaps. The Company's commodity price hedges and interest rate swaps are valued based on discounted future cash flow models that are primarily based on published forward commodity price curves and published LIBOR forward curves; thus, these inputs are designated as Level 2 within the valuation hierarchy.

The fair values of derivative instruments in asset positions include measures of counterparty nonperformance risk, and the fair values of derivative instruments in liability positions include measures of the Company's nonperformance risk. These measurements were not material to the Consolidated Financial Statements.

Share-based Compensation Liability

Certain of our performance-based stock awards ("PSUs") may be payable in cash. The Company classifies the awards that may be settled in cash as liability awards. These awards are valued quarterly utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes grant date fair value based on the most likely outcome. The inputs for the Monte Carlo model are designated as Level 2 within the valuation hierarchy. The share-based compensation liability related to the PSU liability awards is included in Accrued expenses and Other noncurrent liabilities in the Consolidated Balance Sheet as of December 31, 2021.

The following table summarizes the fair value of the Company's financial assets and liabilities, by level within the fair-value hierarchy *(in thousands)*:

December 31, 2021	**Level 1**	**Level 2**	**Level 3**	**Total**
Financial assets				
Derivative asset- current	$ —	$ 1,348	$ —	$ 1,348
Derivative asset- noncurrent	—	157	—	157
Total financial assets	$ —	$ 1,505	$ —	$ 1,505
Financial liabilities				
Derivative liability - current	$ —	$ 45,310	$ —	$ 45,310
Derivative liability - noncurrent	—	571	—	571
Share-based compensation liability - noncurrent	—	14,159	—	14,159
Total financial liabilities	$ —	$ 60,040	$ —	$ 60,040
December 31, 2020				
Financial assets				
Derivative asset- current	$ —	$ 7,509	$ —	$ 7,509
Derivative asset- noncurrent	—	396	—	396
Total financial assets	$ —	$ 7,905	$ —	$ 7,905
Financial liabilities				
Derivative liability - current	$ —	$ 1,135	$ —	$ 1,135
Derivative liability - noncurrent	—	173	—	173
Total financial liabilities	$ —	$ 1,308	$ —	$ 1,308

Other financial instruments include cash, accounts receivable and payable, and revenue royalties. The carrying amount of these instruments approximates fair value because of their short-term nature. The Company's long-term debt obligation bears interest at floating market rates, therefore carrying amounts and fair value are approximately equal.

Fair Value on a Nonrecurring Basis

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including oil and gas properties, goodwill, business combinations and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments if events or changes in certain circumstances indicate that adjustments may be necessary. Due to significant declines in commodity prices and global demand for oil and natural gas products resulting from the COVID-19 pandemic, the Company assessed the fair values of its oil and natural gas properties and goodwill resulting in non-cash impairment charges during the three months ended March 31, 2020. Since then, commodity prices have recovered and no other such triggering events that require further assessment were observed during the year ended December 31, 2021.

Note 6. Derivative Financial Instruments

Commodity Derivative Instruments

The Company's hedging activities consist of derivative instruments entered into in order to hedge against changes in oil and natural gas prices through the use of fixed price swaps, basis swaps and costless collars. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. Costless collars set both a maximum (sold ceiling) and a minimum (bought floor) future price. Consistent with its hedging policy, the Company has entered into a series of derivative instruments to hedge a significant portion of its expected oil and natural gas production through December 31, 2021. Typically, these derivative instruments require payments to (receipts from) counterparties based on specific indices as required by the derivative agreements. Although not risk free, the Company believes these instruments reduce its exposure to oil and natural gas price fluctuations and, thereby, allow the Company to achieve a more predictable cash flow.

The Company's derivative instruments are cash flow hedge transactions in which it is hedging the variability of cash flow related to a forecasted transaction. The Company does not enter into derivative instruments for trading or other speculative purposes. These transactions are recorded in the Consolidated Financial Statements in accordance with FASB ASC Topic 815. The Company has accounted for these transactions using the mark-to-market accounting method. Generally, the Company incurs accounting losses on derivatives during periods where prices are rising and gains during periods where prices are falling which may cause significant fluctuations in the Consolidated Balance Sheets and Consolidated Statements of Operations.

The Company nets its derivative instrument fair value amounts executed with each counterparty pursuant to an International Swap Dealers Association Master Agreement ("ISDA"), which provides for net settlement over the term of the contract. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

The following table sets forth the Company's outstanding derivative contracts at December 31, 2021. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2022	Crude Oil Swap	2,768,250	$57.69
2022	Crude Oil Basis Swap(1)	3,832,500	$0.51
2022	Natural Gas Swap	5,900,000	$3.20
2022	Natural Gas Basis Swap(2)	9,100,000	$(0.26)
2023	Natural Gas Swap	1,375,000	$3.27

(1) The basis differential price is between WTI Midland Argus Crude and the WTI NYMEX.
(2) The basis differential price is between W. Texas (WAHA) and the Henry Hub NYMEX.

	Costless Collars			
Period	Commodity	Volume (Bbls / MMBtu)	Bought Floor ($/Bbl / $/MMBtu)	Sold Ceiling ($/Bbl / $/MMBtu)
2022	Crude Oil Costless Collar	730,000	$60.00	$73.73
2023	Crude Oil Costless Collar	365,000	$55.00	$71.75
2022	Natural Gas Costless Collar	4,037,500	$3.43	$5.10
2023	Natural Gas Costless Collar	888,000	$3.25	$5.13

Interest Rate Swaps

At times, the Company's hedging activities include the use of interest rate swaps entered into in order to manage cash flow variability resulting from changes in interest rates. These derivative instruments are not accounted for under hedge accounting.

In December 2021, the Company unwound its interest rate swap contracts, receiving a one-time settlement payment of $1.1 million. The Company had no interest rate swaps in place as of December 31, 2021.

The following table summarizes the location and fair value amounts of all derivative instruments in the Consolidated Balance Sheets as well as the gross recognized derivative assets, liabilities, and amounts offset in the Consolidated Balance Sheets *(in thousands)*:

		December 31, 2021			December 31, 2020		
Derivatives not designated as hedging contracts under ASC Topic 815	Balance Sheet Location	Gross Recognized Assets / Liabilities	Gross Amounts Offset	Net Recognized Assets / Liabilities	Gross Recognized Assets / Liabilities	Gross Amounts Offset	Net Recognized Assets / Liabilities
Commodity contracts	Derivative asset - current	$ 3,191	$ (1,843)	$ 1,348	$ 11,071	$ (3,562)	$ 7,509
Commodity contracts	Derivative liability - current	$ 47,153	$ (1,843)	$ 45,310	$ 4,492	$ (3,562)	$ 930
Interest rate swaps	Derivative liability - current	$ —	$ —	$ —	$ 205	$ —	$ 205
Commodity contracts	Derivative asset - noncurrent	$ 2,721	$ (2,564)	$ 157	$ 396	$ —	$ 396
Commodity contracts	Derivative liability - noncurrent	$ 3,135	$ (2,564)	$ 571	$ —	$ —	$ —
Interest rate swaps	Derivative liability - noncurrent	$ —	$ —	$ —	$ 173	$ —	$ 173

The follow table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivatives instruments in the Company's Consolidated Statements of Operations and Consolidated Statements of Cash Flows *(in thousands)*:

Derivatives not designated as hedging contracts under ASC Topic 815			Years Ended December 31,		
	Statement of Cash Flows Location	Statement of Operations Location	2021	2020	2019
Unrealized (loss) gain	Not presented separately	Not presented separately	$ (40,795)	$ 3,855	$ (59,849)
Realized (loss) gain	Operating portion of net cash received in settlement of derivative contracts	Not presented separately	(75,966)	56,044	15,866
	Total loss (gain) on derivative contracts, net	(Loss) gain on derivative contracts, net	$ (116,761)	$ 59,899	$ (43,983)

Note 7. Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and natural gas properties. Under this method, costs to acquire oil and natural gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are charged to operations as incurred. Upon sale or retirement of oil and natural gas properties, the costs and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss is recognized.

Costs incurred to maintain wells and related equipment, lease and well operating costs, and other exploration costs are charged to expense as incurred. Gains and losses arising from the sale of properties are included in operating income in the Consolidated Statements of Operations.

The Company's lease acquisition costs and development costs of proved oil and natural gas properties are amortized using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively. Depletion expense for oil and natural gas producing property and related equipment was $105.7 million, $95.9 million and $68.5 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Proved Oil and Natural Gas Properties

Proved oil and natural gas properties are reviewed for impairment on a nonrecurring basis. The impairment charge reduces the carrying values to their estimated fair values. These fair value measurements are classified as Level 3 measurements and include many unobservable inputs. Fair value is calculated as the estimated discounted future net cash flows attributable to the assets. The Company's primary assumptions in preparing the estimated discounted future net cash flows to be recovered from oil and natural gas properties are based on (i) proved reserves, (ii) forward commodity prices and assumptions as to costs and expenses, and (iii) the estimated discount rate that would be used by potential purchasers to determine the fair value of the assets.

Unproved Oil and Natural Gas Properties

Unproved properties consist of costs incurred to acquire undeveloped leases as well as the cost to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisition costs are capitalized. Unproved oil and natural gas leases are generally for a primary term of three to five years. In most cases, the term of the unproved leases can be extended by paying delay rentals, meeting contractual drilling obligations, or by the presence of producing wells on the leases. Unproved costs related to successful exploratory drilling are reclassified to proved properties and depleted on a units-of-production basis.

The Company reviews its unproved properties periodically for impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current exploration and development plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, the Company's geologists' evaluation of the property, and the remaining months in the lease term for the property.

Impairments to Oil and Natural Gas Properties

The Company recorded no non-cash asset impairment charges for the year ended December 31, 2021.

During the year ended December 31, 2020, primarily as a result of the decline in crude oil price futures, the Company recorded non-cash impairment charges of $25.3 million to its proved oil and natural gas properties and $13.2 million to its unproved oil and natural gas properties, located in the Eagle Ford Trend. As a result of certain acreage expirations, the Company recorded non-cash impairment charges of $8.4 million to its unproved oil and natural gas properties during the year ended December 31, 2020.

The Company recorded no non-cash asset impairment charges for the year ended December 31, 2019.

Accumulated impairments to proved and unproved oil and natural gas properties as of December 31, 2021 and 2020 were $168.0 million and $168.0 million, respectively.

Note 8. Noncontrolling Interest

Earthstone consolidates the financial results of EEH and its subsidiaries, and records a noncontrolling interest for the economic interest in Earthstone held by the members of EEH other than Earthstone and Lynden US. Net income attributable to noncontrolling interest in the Consolidated Statements of Operations for the year ended December 31, 2021 represents the portion of net income attributable to the economic interest in the Company held by the members of EEH other than Earthstone and Lynden US. Noncontrolling interest in the Consolidated Balance Sheet as of December 31, 2021 represents the portion of net assets of the Company attributable to the members of EEH other than Earthstone and Lynden US.

The following table presents the changes in noncontrolling interest for the year ended December 31, 2021:

	EEH Units Held By Earthstone and Lynden US	%	EEH Units Held By Others	%	Total EEH Units Outstanding
As of December 31, 2020	30,343,421	46.4 %	35,009,371	53.6 %	65,352,792
EEH Units issued in connection with the IRM Acquisition	12,719,594		—		12,719,594
EEH Units issued in connection with the Tracker/Sequel Acquisitions	6,200,000		—		6,200,000
EEH Units issued in connection with the Foreland Acquisition	2,611,111		—		2,611,111
EEH Units issued in connection with the vesting of restricted stock units	928,342		—		928,342
EEH Units and Class B Common Stock converted to Class A Common Stock	664,839		(664,839)		—
As of December 31, 2021	53,467,307	60.9 %	34,344,532	39.1 %	87,811,839

Note 9. Net Income (Loss) Per Common Share

Net income (loss) per common share—basic is calculated by dividing Net income (loss) by the weighted average number of shares of common stock outstanding during the period. Net income (loss) per common share—diluted assumes the conversion of all potentially dilutive securities and is calculated by dividing Net income (loss) by the sum of the weighted average number of shares of common stock, as defined above, outstanding plus potentially dilutive securities. Net income (loss) per common share—diluted considers the impact of potentially dilutive securities except in periods in which there is a loss because the inclusion of the potential common shares, as defined above, would have an anti-dilutive effect.

A reconciliation of Net income (loss) per common share is as follows:

	Years Ended December 31,		
(In thousands, except per share amounts)	2021	2020	2019
Net income (loss) attributable to Earthstone Energy, Inc.	$ 35,484	$ (13,547)	$ 719
Net income (loss) per common share attributable to Earthstone Energy, Inc.:			
Basic	$ 0.75	$ (0.45)	$ 0.02
Diluted	$ 0.71	$ (0.45)	$ 0.02
Weighted average common shares outstanding			
Basic	47,169,948	29,911,625	28,983,354
Add potentially dilutive securities:			
Unvested restricted stock units	539,803	—	—
Unvested performance units	2,242,342	—	377,531
Diluted weighted average common shares outstanding	49,952,093	29,911,625	29,360,885

The Class B common stock, $0.001 par value per share of Earthstone (the "Class B Common Stock"), has been excluded, as its conversion would eliminate noncontrolling interest and Net income attributable to noncontrolling interest of $26.0 million for the year ended December 31, 2021, Net loss attributable to noncontrolling interest of $15.9 million for the year ended December 31, 2020, and Net income attributable to noncontrolling interest of $0.9 million for the year ended December 31, 2019 would be added back to Net income (loss) attributable to Earthstone Energy, Inc. for the years then ended, having no dilutive effect on Net income (loss) per common share attributable to Earthstone Energy, Inc. For the year ended December 31, 2020, the Company excluded 1.1 million and 1.9 million shares, respectively, for the dilutive effect of restricted stock units and performance units in calculating diluted earnings per share as the effect was anti-dilutive due to the net loss incurred for the period.

Note 10. Common Stock

Class A Common Stock

At December 31, 2021 and 2020, there were 53,467,307 and 30,343,421 shares of Class A Common Stock issued and outstanding, respectively. During the year ended December 31, 2021, Earthstone issued a total of approximately 21.5 million shares of Class A Common Stock in connection with the IRM Acquisition, Tracker/Sequel Acquisitions and the Foreland Acquisition. No shares were issued in connection with acquisitions during 2020 or 2019. During the years ended December 31, 2021, 2020 and 2019, as a result of the vesting and settlement of restricted stock units under the Earthstone Amended and Restated 2014 Long-Term Incentive Plan, as amended (the "2014 Plan"), Earthstone issued 1,381,825, 914,905 and 736,706 shares of Class A Common Stock, respectively, of which 453,483, 243,924 and 203,394 shares of Class A Common Stock, respectively, were retained as treasury stock and canceled to satisfy the related employee income tax liability.

Class B Common Stock

At December 31, 2021 and 2020, there were 34,344,532 and 35,009,371 shares of Class B Common Stock issued and outstanding, respectively. Each share of Class B Common Stock, together with one EEH Unit, is convertible into one share of Class A Common Stock. During the years ended December 31, 2021, 2020 and 2019, 664,839, 251,309 and 191,498 shares, respectively, of Class B Common Stock and EEH Units were exchanged for an equal number of shares of Class A Common Stock.

Note 11. Stock-Based Compensation

Restricted Stock Units

The 2014 Plan allows, among other things, for the grant of restricted stock units ("RSUs"). As of December 31, 2021, the maximum number of shares of Class A Common Stock that may be issued under the 2014 Plan was 12.0 million shares.

Each RSU represents the contingent right to receive one share of Class A Common Stock. The holders of outstanding RSUs do not receive dividends or have voting rights prior to vesting and settlement. The Company determines the fair value of granted RSUs based on the market price of the Class A Common Stock on the date of the grant. Compensation expense for granted RSUs is recognized on a straight-line basis over the vesting term and is net of forfeitures, as incurred. Stock-based compensation is included in General and administrative expense in the Consolidated Statements of Operations and is recorded with a corresponding increase in Additional paid-in capital within the Consolidated Balance Sheets.

The table below summarizes unvested RSU activity for the year ended December 31, 2021:

	Shares	Weighted-Average Grant Date Fair Value
Unvested RSUs at December 31, 2020	1,050,908	$ 5.55
Granted	668,000	$ 6.16
Forfeited	(20,266)	$ 5.09
Vested	(926,825)	$ 5.71
Unvested RSUs at December 31, 2021	771,817	$ 5.91

During the year ended December 31, 2021, Earthstone granted 548,000 RSUs to employees and 120,000 RSUs to certain members of the Board with vesting periods ranging from 12 to 36 months. The total grant date fair value of the RSUs granted during the years ended December 31, 2021, 2020 and 2019 were $4.1 million, $4.4 million and $6.5 million, respectively, with a weighted average grant date fair value per share of $6.16, $5.07 and 6.04, respectively. The total vesting date fair value of the RSUs that vested during 2021, 2020 and 2019 was $8.8 million, $3.0 million and $4.2 million, respectively. As of December 31, 2021, there was approximately $4.5 million of total unrecognized stock-based compensation expense related to unvested

RSUs, which will be amortized over the remaining vesting periods. The weighted average remaining vesting period of the unrecognized compensation expense is 1.04 years.

For the years ended December 31, 2021, 2020 and 2019, stock-based compensation related to RSUs was $5.2 million, $5.4 million and $5.9 million, respectively.

Performance Units

The table below summarizes performance unit ("PSU") activity for the year ended December 31, 2021:

	Shares	Weighted-Average Grant Date Fair Value
Unvested PSUs at December 31, 2020	1,879,425	$ 7.65
Granted	1,099,800	$ 10.85
Vested	(227,500)	$ 13.75
Unvested PSUs at December 31, 2021	2,751,725	$ 8.42

The total grant date fair value of the PSUs granted during the years ended December 31, 2021, 2020 and 2019 were $11.9 million, $5.6 million and $6.2 million, respectively, with a weighted average grant date fair value per share of $10.85, $5.36 and $9.30, respectively. The total vesting date fair value of the PSUs that vested during 2021 was $3.5 million. No PSUs vested during 2020 or 2019. As of December 31, 2021, there was $16.0 million of unrecognized compensation expense related to the PSU awards which will be amortized over a weighted average period of 0.96 years.

For the years ended December 31, 2021, 2020 and 2019, stock-based compensation related to the PSUs was approximately $15.8 million, $4.6 million and $2.7 million, respectively.

On January 27, 2021, the Board of Directors of Earthstone (the "Board") granted 1,099,800 PSUs (the "2021 PSUs") to certain officers pursuant to the 2014 Plan (the "2021 Grant"). The 2021 PSUs are payable in cash or shares of Class A Common Stock upon the achievement by the Company over a period commencing on January 1, 2021 and ending on December 31, 2023 of certain performance criteria established by the Board. The Company classifies these awards that will be settled in cash as liability awards. PSU grants to be settled in shares are classified as equity awards.

The 2021 PSUs are eligible to be earned based on the annualized Total Shareholder Return ("TSR") of the Class A Common Stock during a three-year period beginning on February 1, 2021. Between 0x to 2.0x of the Performance Units are eligible to be earned based on Earthstone achieving an annualized TSR based on the following pre-established goals:

Earthstone's Annualized TSR	TSR Multiplier
20.5% or greater	2.0
14.5%	1.0
7.7%	0.5
Less than 7.7%	0.0

In the event that greater than 1.0x of the 2021 PSUs are earned, such additional PSUs may be paid in cash rather than the issuance of shares of Class A Common Stock.

The Company accounts for these awards as market-based awards which are valued quarterly utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes grant date fair value based on the most likely outcome. For the 2021 PSUs, assuming a risk-free rate of 0.3% and volatility of 86.0%, the Company calculated the weighted average grant date fair value per PSU to be $10.85. Based on the fair value of the 2021 PSUs, the Company recorded stock-based compensation expense of $6.3 million during the year ended December 31, 2021. A corresponding liability of $6.3 million related to the 2021 PSUs is included in Other noncurrent liabilities in the Consolidated Balance Sheet as of December 31, 2021.

On January 30, 2020, the Board granted 1,043,800 PSUs (the "2020 PSUs") to certain officers pursuant to the 2014 Plan (the "2020 Grant"). The 2020 Grant was subject to the approval of an amendment to the 2014 Plan to increase the number of available shares available thereunder (the "2014 Plan Amendment"). The 2014 Plan Amendment was approved at the 2020 annual meeting of stockholders held on June 3, 2020. The 2020 PSUs are payable in shares of Class A Common Stock based upon the achievement by the Company over a period commencing on February 1, 2020 and ending on January 31, 2023 of certain performance criteria established by the Board.

The 2020 PSUs are eligible to be earned based on the annualized TSR of the Class A Common Stock during a three-year period beginning on February 1, 2020. Between 0x to 2.0x of the Performance Units are eligible to be earned based on Earthstone achieving an annualized TSR based on the following pre-established goals:

Earthstone's Annualized TSR	**TSR Multiplier**
23.9% or greater	2.0
14.5%	1.0
8.4%	0.5
Less than 8.4%	0.0

In the event that greater than 1.0x of the 2020 PSUs are earned, such additional PSUs may be paid in cash rather than the issuance of shares of Class A Common Stock, solely at the discretion of the Board.

The Company accounts for these awards as market-based awards which are valued utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes grant date fair value based on the most likely outcome. For the 2020 PSUs, assuming a risk-free rate of 1.4% and volatility of 62.0%, the Company calculated the weighted average grant date fair value per PSU to be $5.36.

On January 28, 2019, the Board granted 669,550 PSUs (the "2019 PSUs") to certain executive officers pursuant to the 2014 Plan. The PSUs are payable in shares of Class A Common Stock based upon the achievement by the Company over a period commencing on February 1, 2019 and ending on January 31, 2022 of performance criteria established by the Board.

The number of shares of Class A Common Stock that may be issued will be determined by multiplying the number of PSUs granted by the Relative TSR Percentage (0% to 200%). The "Relative TSR Percentage" is the percentage, if any, achieved by attainment of a certain predetermined range of targets for the three-year period beginning on February 1, 2019.

TSR for the Company and each of the peer companies is generally determined by dividing (A) the volume weighted average price of a share of stock for the trading days during the thirty calendar days ending on and including the last calendar day of the applicable performance period minus the volume weighted average price of a share of stock for the trading days during the thirty calendar days ending on and including the first day of the applicable performance period plus cash dividends paid over the applicable performance period by (B) the volume weighted average price of a share of stock for the trading days during the thirty calendar days ending on and including the first day of the applicable performance period.

The Company accounts for these awards as market-based awards which are valued utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes grant date fair value based on the most likely outcome. For the PSUs granted on January 28, 2019, assuming a risk-free rate of 2.6% and volatilities ranging from 40.1% to 114.1%, the Company calculated the weighted average grant date fair value per PSU to be $9.30.

Modification of Performance Units

The 2019 PSUs were initially classified as equity awards as the intention was to fully settle in shares. As of December 31, 2021, and at discretion of the Board, the 2019 PSUs in excess of 100% were to be settled in cash. This event was treated as a modification of the award with the bifurcated cash settled portion of the award being remeasured and classified as a liability award. The Company calculated the fair value of the cash settled portion of the award to be $13.66, resulting in $5.5 million additional stock-based compensation during the year ended December 31, 2021, $2.3 million of stock-based compensation previously recognized in Additional Paid-in Capital being reclassified with a corresponding liability of $7.8 million included in Accrued Expenses in the Consolidated Balance Sheet as of December 31, 2021. The 2019 PSUs were settled on February 9, 2022 resulting in the issuance of 608,125 shares of Class A Common Stock and cash payments totaling $8.1 million.

Note 12. Long-Term Debt

Credit Agreement

On November 21, 2019, Earthstone, EEH (the "Borrower"), Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank ("Wells Fargo"), BOKF, NA dba Bank of Texas, as Issuing Bank with respect to Existing Letters of Credit, Royal Bank of Canada, as Syndication Agent, Truist Bank, as successor by merger to SunTrust Bank, as Documentation Agent, and the Lenders party thereto (collectively, the "Parties") entered into a credit agreement (the "Credit Agreement"), which replaced the prior credit facility, which was terminated on November 21, 2019.

On December 17, 2020, Earthstone, EEH, as Borrower, Wells Fargo, as Administrative Agent, the guarantors party thereto, and the lenders party thereto (the "Lenders") entered into an amendment (the "Second Amendment") to the Credit Agreement. The Second Amendment was effective upon the closing of the IRM Acquisition described in *Note 3. Acquisitions and Divestitures*.

Among other things, the Second Amendment (i) joined certain financial institutions as additional lenders, increased the borrowing base from $240.0 million to $360.0 million, (ii) increased the interest rate on outstanding borrowings; and (iii) adjusted some of the financial covenants.

On April 20, 2021, the Parties entered into an amendment (the "Third Amendment") to the Credit Agreement under which the borrowing base increased from $360 million to $475 million in connection with its regularly scheduled redetermination. Further, the Third Amendment provided for an increase in the borrowing base from $475 million to $550 million which became effective on July 20, 2021 upon closing of the Tracker/Sequel Purchase Agreements described in *Note 3. Acquisitions and Divestitures*.

On September 17, 2021, Earthstone, EEH, as Borrower, Wells Fargo as Administrative Agent and Issuing Bank, the lenders party thereto (the "Lenders") and the guarantors party thereto entered into an amendment (the "Fourth Amendment") to the Credit Agreement. Among other things, the Fourth Amendment increased the borrowing base from $550 million to $650 million in connection with its regularly scheduled semi-annual redetermination, added provisions to provide for the eventual replacement of LIBOR as a benchmark interest rate, made certain changes to the lenders under the Credit Agreement, and made certain other administrative changes to the Credit Agreement.

The next regularly scheduled redetermination of the borrowing base is expected to occur on or around May 1, 2022. Subsequent redeterminations are expected to occur on or about each November 1st and May 1st thereafter. The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the adjusted SOFR Rate (as customarily defined) (the "Adjusted Term SOFR Rate") plus 2.50% to 4.25% or (b) the sum of (i) the greatest of (A) the prime rate of Wells Fargo, (B) the federal funds rate plus ½ of 1.0%, and (C) the Adjusted Term SOFR Rate for an interest rate period of one month plus 1.0%, (ii) plus 1.50% to 3.25%, depending on the amount borrowed under the Credit Agreement. Principal amounts outstanding under the Credit Agreement are due and payable in full at maturity on November 21, 2024. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of EEH's assets. Additional payments due under the Credit Agreement include paying a commitment fee of 0.375% to 0.50% per year, depending on the amount borrowed under the Credit Agreement, to the Lenders in respect of the unutilized commitments thereunder. EEH is also required to pay customary letter of credit fees.

The Credit Agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, EEH's ability to incur additional indebtedness, create liens on assets, make investments, pay dividends and distributions or repurchase its limited liability interests, engage in mergers or consolidations, sell certain assets, sell or discount any notes receivable or accounts receivable and engage in certain transactions with affiliates.

In addition, the Credit Agreement requires EEH to maintain the following financial covenants: a current ratio, (as such term is defined in the Credit Agreement) of not less than 1.0 to 1.0 and a consolidated leverage ratio of not greater than 3.5 to 1.0. Consolidated leverage ratio means the ratio of (i) the aggregate debt of EEH and its consolidated subsidiaries as at the last day of the fiscal quarter to (ii) EBITDAX for the applicable period, which was calculated as EBITDAX for the four consecutive fiscal quarters ending on such date. The term "EBITDAX" means, for any period, the sum of consolidated net income (loss) for such period plus (a) the following expenses or charges to the extent deducted from consolidated net income (loss) in such period: (i) interest, (ii) taxes, (iii) depreciation, (iv) depletion, (v) amortization, (vi) certain distributions to employees related to the stock compensation, (vii) certain transaction related expenses, (viii) reimbursed indemnification expenses related to certain dispositions and investments, (ix) non-cash extraordinary, usual, or nonrecurring expenses or losses, (x) other non-cash charges and minus (b) to the extent included in consolidated net income (loss) in such period: (i) non-cash income, (ii) gains on asset dispositions, disposals and abandonments outside of the ordinary course of business and (iii) to the extent not otherwise deducted from consolidated net income (loss), the aggregate amount of any pass-through cash distributions received by Borrower during such period in an amount equal to the aggregate amount of pass-through cash distributions actually made by Borrower during such period.

The Credit Agreement contains customary affirmative covenants and defines events of default to include failure to pay principal or interest, breach of covenants, breach of representations and warranties, insolvency, judgment default and a change in control. Upon the occurrence and continuance of an event of default, the Lenders have the right to accelerate repayment of the loans and exercise their remedies with respect to the collateral. As of December 31, 2021, EEH was in compliance with the covenants under the Credit Agreement.

As of December 31, 2021, the Company had a $650.0 million borrowing base under the Credit Agreement, of which $320.0 million was outstanding, bearing annual interest of 3.110%, resulting in an additional $330.0 million of borrowing base availability under the Credit Agreement. At December 31, 2020, there were $115.0 million of borrowings outstanding under the Credit Agreement.

For the year ended December 31, 2021, the Company had borrowings of $744.1 million and $539.1 million in repayments of borrowings.

For the years ended December 31, 2021, 2020 and 2019, interest on all outstanding debt averaged 3.40%, 2.83% and 4.42% per annum, respectively, which excluded commitment fees of $0.9 million, $0.6 million and $0.7 million for each period ended, respectively, and amortization of deferred financing costs of $0.9 million, $0.3 million and $0.4 million for each period ended, respectively.

The Company capitalized $2.8 million of costs associated with the Credit Agreement for the year ended December 31, 2021. No costs associated with the Credit Agreement were capitalized during the year ended December 31, 2020. The Company capitalized $1.6 million of costs associated with the Credit Agreement for the year ended December 31, 2019. These capitalized costs are included in Other noncurrent assets in the Consolidated Balance Sheets. The Company's policy is to capitalize the financing costs associated with its debt and amortize those costs on a straight-line basis over the term of the associated debt, which approximates the effective interest method over the term of the related debt.

Note 13. Asset Retirement Obligations

The Company has asset retirement obligations associated with the future plugging and abandonment of oil and natural gas properties and related facilities. Revisions to the liability typically occur due to changes in the estimated abandonment costs, well economic lives, and the discount rate.

The following table summarizes the Company's asset retirement obligation transactions recorded during the years ended December 31, 2021 and 2020 *(in thousands)*:

	2021	2020
Beginning asset retirement obligations	$ 3,027	$ 2,164
Associated with acquisitions	9,821	—
Liabilities incurred	163	106
Property dispositions	(41)	(10)
Liabilities settled	(185)	(195)
Accretion expense	1,065	307
Revision of estimates	2,016	655
Ending asset retirement obligations	$ 15,866	$ 3,027

Note 14. Related Party Transactions

FASB ASC Topic 850, Related Party Disclosures, requires that information about transactions with related parties that would make a difference in decision making shall be disclosed so that users of the financial statements can evaluate their significance. The Audit Committee of the Board independently reviews and approves all related party transactions.

Earthstone has two significant shareholders that consist of various investment funds managed by each of the two private equity firms who may manage other investments in entities with which the Company interacts in the normal course of business (the "Significant Shareholders" or separately, each a "Significant Shareholder").

On February 12, 2020, the Company sold certain of its interests in oil and natural gas leases and wells in an arm's length transaction to a portfolio company of a Significant Shareholder (not under common control) for cash consideration of approximately $0.4 million.

In connection with the Olenik v. Lodzinski et al. lawsuit described below in *Note 15. Commitments and Contingencies*, a Significant Shareholder was also named in the lawsuit. As a result of a settlement agreement relating to the lawsuit, the Company agreed with its insurance carrier regarding an allocation of defense costs and settlement contributions above its deductible for all the parties named in the lawsuit. In connection with the Court approved settlement, the Significant Shareholder was billed approximately $1.1 million in fiscal 2020 and all amounts have been received.

As discussed in *Note 3. Acquisitions and Divestitures*, on March 31, 2021, the Company entered into the Tracker/Sequel Purchase Agreements. The Tracker/Sequel Acquisitions were consummated on July 20, 2021, whereby the Company acquired the Tracker Assets for a purchase price of $18.8 million in cash and 4.7 million shares of Class A Common Stock. A Significant Shareholder owned approximately 49% of Tracker as of the closing of the Tracker Acquisition. A majority of the stockholders of Earthstone not affiliated with the Significant Shareholder approved the issuance of 6.2 million shares of Class A Common Stock in connection with the closing of the Tracker/Sequel Purchase Agreements at Earthstone's Annual Meeting of Stockholders held on July 20, 2021.

As discussed in *Note 3. Acquisitions and Divestitures*, during the second quarter of 2021, the Company completed the Eagle Ford Acquisitions for a purchase price of approximately $45.2 million in cash. A Significant Shareholder controlled one of the four sellers. After participating in a competitive sales process, the Company acquired the aforementioned assets for $8.2 million in cash from that related party entity.

On February 15, 2022, Earthstone, EEH, Chisholm Energy Operating, LLC ("OpCo") and Chisholm Energy Agent, Inc. ("Agent" and collectively with OpCo, "Chisholm"), as seller, consummated the transaction (the "Chisholm Closing") contemplated in that certain Purchase and Sale Agreement dated December 15, 2021 (the "Chisholm Agreement") by and among Earthstone, EEH and Chisholm. At the closing of the Chisholm Agreement, among other things, EEH acquired (the "Chisholm Acquisition") interests in oil and gas leases and related property of Chisholm located in Lea County and Eddy County, New Mexico, for aggregate consideration consisting of: (i) approximately $314.7 million in cash, net of preliminary and customary purchase price adjustments and remains subject to post-closing settlement between EEH and Chisholm paid at the closing of the Chisholm Acquisition, (ii) $70 million in cash to be paid as follows: $40 million to be paid six months after the closing of the Chisholm Acquisition and $30 million to be paid 12 months after the closing of the Chisholm Acquisition, subject to acceleration in the event that Earthstone receives gross proceeds of more than $450 million from a high yield bond offering or more than $50 million in gross proceeds from an offering of Class A Common Stock or preferred stock; and (iii) 19,417,476 shares of Class A Common Stock. On December 17, 2021, in accordance with the Chisholm Agreement and prior to the Chisholm Closing, Earthstone provided a deposit in the amount of $30.5 million which was recorded in Other noncurrent assets in the Consolidated Balance Sheeet as of December 31, 2021, as well as included in Acquisition of oil and gas properties in Cash flows from investing activities in the Consolidated Statements of Cash Flows for the year then ended. A Significant Shareholder was the majority owner of Chisholm as of the closing of the Chisholm Acquisition. A majority of the stockholders of Earthstone not affiliated with the Significant Shareholder approved the issuance of 19,417,476 shares of Class A Common Stock in connection with the closing of the Chisholm Acquisition.

Note 15. Commitments and Contingencies

Contractual Commitments

Future minimum contractual commitments as of December 31, 2021 under non-cancelable agreements having initial or remaining terms in excess of one year are as follows:

	2022	2023	2024	2025	2026	Thereafter
Office leases	696	595	605	152	—	—
Total	$ 696	$ 595	$ 605	$ 152	$ —	$ —

Additionally, the Company leases corporate office space in The Woodlands, Texas and Midland, Texas. Rent expense was approximately $0.8 million, $0.8 million and $0.8 million, for the years ended December 31, 2021, 2020 and 2019, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2021 are included in the table above.

Environmental

The Company's operations are subject to risks normally associated with the drilling, completion and production of oil and gas, including blowouts, fires, and environmental risks such as oil spills or gas leaks that could expose the Company to liabilities associated with these risks.

In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of prior environmental safeguards, if any, that were taken at the time such wells were drilled or during such time the wells were operated. The Company maintains comprehensive insurance coverage that it believes is adequate to mitigate the risk of any adverse financial effects associated with these risks.

However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still fall upon the Company. No claim has been made, nor is the Company aware of any liability which the Company may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations relating thereto except for the matter discussed above.

Legal

From time to time, Earthstone and its subsidiaries may be involved in various legal proceedings and claims in the ordinary course of business.

Olenik v. Lodzinski et al.: On June 2, 2017, a purported shareholder class and derivative action in the Delaware Court of Chancery was filed against Earthstone's Chief Executive Officer, along with other members of the Board, EnCap Investments L.P. ("EnCap"), Bold Energy Holdings, LLC ("Bold Holdings"), and Bold Energy III LLC ("Bold") and Oak Valley Resources, LLC. The complaint alleged that Earthstone's directors breached their fiduciary duties in connection with the contribution agreement dated as of November 7, 2016 and as amended on March 21, 2017 (the "Bold Contribution Agreement"), by and among Earthstone, EEH, Lynden US, Lynden USA Operating, LLC, Bold Holdings and Bold. The Plaintiff asserted that the directors negotiated the business combination pursuant to the Bold Contribution Agreement (the "Bold Transaction") to the detriment of the Earthstone stockholders who were not affiliated with EnCap or Earthstone management, did not follow an adequate process in negotiating and approving the Bold Transaction and made materially misleading or incomplete proxy disclosures in connection with the Bold Transaction. On July 20, 2018, the Delaware Court of Chancery granted the defendants' motion to dismiss and entered an order dismissing the action in its entirety with prejudice. The Plaintiff filed an appeal with the Delaware Supreme Court. On April 5, 2019, the Delaware Supreme Court affirmed the Delaware Court of Chancery's dismissal of the proxy disclosure claims but reversed the Delaware Court of Chancery's dismissal of the other claims, holding that the allegations with respect to those claims were sufficient for pleading purposes. After engaging in extensive pre-trial discovery, the parties entered into a settlement agreement that was approved by the Delaware Court of Chancery on March 31, 2021. The principal terms of the settlement agreement are: (i) a $3.5 million all-in cash settlement payment (the "Fund") to be funded by defendants and/or their insurers into an escrow account, (ii) a bi-lateral complete and full release of all claims against defendants and plaintiffs, and (iii) 55% of the Fund (the derivative payment) be paid to Earthstone to be used as determined by management, 45% of the Fund (the class payment) be paid to members of the class or current stockholders of Earthstone. Earthstone paid the $3.5 million settlement in April 2021 and the insurance carriers reimbursed their agreed upon allocation of the settlement totaling $2.8 million. In addition, Earthstone has received $1.3 million from the derivative portion of the settlement, which was included as a reduction of Transaction costs in the Consolidated Statement of Operations for the year ended December 31, 2021.

Note 16. Income Taxes

The Company's corporate structure requires the filing of two separate consolidated U.S. Federal income tax returns and one Canadian income tax return which include Lynden US, Earthstone, and Lynden Corp. As such, taxable income of Earthstone cannot be offset by tax attributes, including net operating losses, of Lynden US, nor can taxable income of Lynden US be offset by tax attributes of Earthstone. Earthstone and Lynden US record a tax provision, respectively, for their share of the book income or loss of EEH, net of the non-controlling interest. As EEH is treated as a partnership for U.S. Federal income tax purposes, it is not subject to income tax at the federal level and only recognizes the Texas Margin Tax.

The following table shows the components of the Company's income tax provision for the years ended December 31, 2021, 2020 and 2019 (*in thousands*):

	Years Ended December 31,		
	2021	2020	2019
Current:			
Federal	$ —	$ —	$ —
State	(625)	(545)	—
Total current	(625)	(545)	—
Deferred:			
Federal	(901)	147	(95)
State	(333)	510	(1,570)
Total deferred	(1,234)	657	(1,665)
Total income tax (expense) benefit	$ (1,859)	$ 112	$ (1,665)

Effective Tax Rate

A reconciliation of the effective tax rate to the federal statutory rate for the years ended December 31, 2021, 2020 and 2019 is as follows (*in thousands, except percentages*):

	Years Ended December 31,		
	2021	**2020**	**2019**
Net income (loss) before income taxes	$ 63,365	$ (29,546)	$ 3,245
Statutory rate	21 %	21 %	21 %
Tax (expense) benefit computed at statutory rate	(13,307)	6,204	(681)
Noncontrolling interest	5,613	(3,349)	374
Non-deductible general and administrative expenses	455	(1,943)	(230)
State return to accrual	—	(157)	(286)
State income taxes, net of Federal benefit	(958)	(35)	(1,285)
Valuation allowance	6,338	(608)	443
Total income tax (expense) benefit	$ (1,859)	$ 112	$ (1,665)
Effective tax rate	(2.9)%	(0.4)%	(51.3)%

During the year ended December 31, 2021, the Company recorded total income tax expense of $1.9 million which included (1) deferred income tax expense for Lynden US of $0.9 million as a result of its share of the distributable income from EEH, (2) deferred income tax expense for Earthstone of $6.3 million as a result of its share of the distributable loss from EEH, which was offset by a valuation allowance as future realization of the net deferred tax asset cannot be assured, (3) current income tax expense of $0.63 million and (4) deferred income tax expense of $0.33 million related to the Texas Margin Tax. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2021.

During the year ended December 31, 2020, the Company recorded total income tax benefit of $0.11 million which included (1) deferred income tax benefit for Lynden US of $0.15 million as a result of its share of the distributable income from EEH, (2) deferred income tax benefit for Earthstone of $0.61 million as a result of its share of the distributable income from EEH, which was offset by a valuation allowance as future realization of the net deferred tax asset cannot be assured and (3) current income tax expense of $0.55 million, offset by deferred income tax benefit of $0.51 million related to the Texas Margin Tax. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2020.

During the year ended December 31, 2019, the Company recorded total income tax expense of $1.7 million which included (1) deferred income tax expense for Lynden US of $0.1 million as a result of its share of the distributable income from EEH, (2) deferred income tax expense for Earthstone of $0.4 million as a result of its share of the distributable income from EEH, which was used to reduce the valuation allowance recorded against its deferred tax asset as future realization of the net deferred tax asset cannot be assured and (3) deferred income tax expense of $1.6 million related to the Texas Margin Tax. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2019.

Deferred Tax Assets and Liabilities

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities at December 31, 2021 and 2020 are as follows (*in thousands*):

	Years Ended December 31,	
	2021	**2020**
Deferred noncurrent income tax assets (liabilities):		
Oil & gas properties	$ 20,909	$ 18,929
Basis difference in subsidiary obligation	(2,211)	(2,211)
Investment in Partnerships	(27,463)	(25,760)
Federal net operating loss carryforward	16,544	11,590
Net deferred noncurrent tax (liability) asset	7,779	2,548
Valuation allowance	(23,510)	(17,044)
Net deferred tax liability	$ (15,731)	$ (14,496)

As of December 31, 2021, the Company had a valuation allowance recorded against its deferred tax asset of $23.5 million which is in excess of its net deferred noncurrent tax liabilities of $7.8 million, as presented above. The Company's corporate organizational structure requires the filing of two separate consolidated U.S. Federal corporate income tax returns, one separate U.S. Federal partnership income tax return and one Canadian income tax return. As a result, tax attributes of one group cannot be offset by the tax attributes of another. At December 31, 2021, the deferred tax assets and liabilities related to the two U.S. Federal corporate income tax returns, one Canadian income tax return and one related to the Texas Margin Tax are a $19.7 million deferred tax asset, a $10.4 million deferred tax liability, a $3.8 million deferred tax asset and a $5.3 million deferred tax liability, respectively, before considering the valuation allowance of $23.5 million.

As of December 31, 2020, the Company had a valuation allowance recorded against its deferred tax assets of $17.0 million which is in excess of its Net deferred noncurrent tax assets of $2.5 million, as presented above. The Company’s corporate organizational structure requires the filing of two separate consolidated U.S. Federal income tax returns, one separate U.S. Federal partnership income tax return and one Canadian income tax return. As a result, tax attributes of one group cannot be offset by the tax attributes of another. At December 31, 2020, the deferred tax assets and liabilities related to the two U.S. Federal income tax returns, one Canadian income tax and one related to the Texas Margin Tax were a $13.3 million deferred tax asset, a $9.6 million deferred tax liability, a $3.8 million deferred tax asset and a $4.8 million deferred tax liability, respectively, before considering the valuation allowance of $17.0 million.

As of December 31, 2021, (1) Earthstone had estimated U.S. net operating loss carryforwards of $29.1 million, expiring in 2036 and 2037 and $14.4 million with an indefinite carryforward life (“ICL”), (2) Lynden US had estimated U.S. net operating loss carryforwards of $31.9 million, expiring from 2032 through 2037 and $2.6 million with an indefinite carryforward life, and, (3) Lynden Corp had Canadian net operating loss carryforwards of $10.0 million, the first expiring in 2024 and the last in 2037. ICL loss deductions are limited to 80% of the excess of taxable income in the year utilized. Additionally, the ability to utilize net operating losses and other tax attributes could be subject to a significant limitation if the Company were to undergo an ownership change for the purposes of Section 382 (“Sec 382”) of the Internal Revenue Code of 1986, as amended (the “Code”). The Company has an additional estimated U.S. net operating loss carryforward of $65.9 million limited by Sec 382 resulting from the Lynden Arrangement. The Company continues to evaluate the impact, if any, of potential Sec 382 limitations.

On February 15, 2022, as a result of the completion of the Chisholm Acquisition, which included the issuance of 19,417,476 shares of our Class A Common Stock, a limitation was triggered under Section 382 of the Code. The Company is currently assessing the impact of the limitation on both its NOL and its deferred tax asset.

Uncertain Tax Positions

FASB ASC Topic 740, *Income Taxes* (“ASC 740”) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As of December 31, 2021, the Company had no material uncertain tax positions. The Company’s uncertain tax positions may change in the next twelve months; however, the Company does not expect any possible change to have a significant impact on its results of operations or financial position.

The Company files two Federal income tax returns, one Canadian income tax return and various combined and separate filings in several state and local jurisdictions. The Company’s practice is to recognize estimated interest and penalties, if any, related to potential underpayment of income taxes as a component of income tax expense in its Consolidated Statement of Operations. As of December 31, 2021, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

Note 17. Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan (the “401(k) Plan”) for substantially all of its employees, which was initiated in April 2017. Eligible employees may make contributions to the 401(k) Plan by electing to contribute up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of 100% of employee contributions, not to exceed six percent of the employee’s annual eligible compensation. The Company’s matching contributions vest immediately. The Company’s contributions to the 401(k) Plan for the years ended December 31, 2021, 2020 and 2019 were $0.5 million, $0.5 million and $0.5 million, respectively.

Note 18. Leases

The Company’s operating lease activities consist of leases for office space. The Company’s finance lease activities consist of leases for vehicles. Leases with an initial term of 12 months or less are not recorded on the balance sheet. Most leases include one or more options to renew, with renewal terms generally ranging from one to three years. The exercise of lease renewal options is at the Company’s sole discretion. Certain leases also include options to purchase the leased property. The depreciable life of assets and leasehold improvements is limited by the expected lease term, unless there is a transfer of title or purchase option reasonably certain of exercise. None of the lease agreements include variable lease payments. The lease agreements do not contain any material residual value guarantees or material restrictive covenants.

The following table shows the classification and location of the Company's leases on the Consolidated Balance Sheets *(in thousands)*:

Leases	Balance Sheet Location	December 31, 2021	December 31, 2020
Assets			
Noncurrent:			
Operating	Operating lease right-of-use assets	$ 1,795	$ 2,450
Finance	Office and other equipment, net of accumulated depreciation and amortization	—	74
Total lease assets		$ 1,795	$ 2,524
Liabilities			
Current:			
Operating	Operating lease liabilities	$ 681	$ 773
Finance	Finance lease liabilities	—	69
Noncurrent:			
Operating	Operating lease liabilities	1,276	1,840
Finance	Finance lease liabilities	—	5
Total lease liabilities		$ 1,957	$ 2,687

The following table shows the classification and location of the Company's lease costs on the Consolidated Statements of Operations *(in thousands)*:

	Statement of Operations Location	Years Ended December 31, 2021	2020	2019
Operating lease expense	General and administrative expense	$ 803	$ 786	$ 754
Finance lease expense:				
Amortization of right-of-use assets	Depreciation, depletion and amortization	$ 74	$ 217	$ 298
Interest on lease liability	Interest expense, net	2	13	33
Total lease expense		$ 879	$ 1,016	$ 1,085

Additionally, the Company capitalized as part of oil and gas properties $6.4 million, $2.9 million and $11.4 million of short-term lease costs related to drilling rig contracts during the years ended December 31, 2021, 2020 and 2019. All of the Company's drilling rig contracts have enforceable terms of less than one year.

Minimum contractual obligations for the Company's leases (undiscounted) as of December 31, 2021 were as follows *(in thousands)*:

	Operating	Finance
2022	$ 696	$ —
2023	595	—
2023	605	—
2025	152	—
2026	—	—
Thereafter	—	—
Total lease payments	$ 2,048	$ —
Less imputed interest	(91)	—
Total lease liability	$ 1,957	$ —

The following table shows the weighted average remaining lease term and the weighted average discount rate for the Company's leases as of the dates indicated:

	December 31, 2021		December 31, 2020	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted-average remaining lease term (in years)	2.9	n/a	3.9	1.0
Weighted-average discount rate (1)	4.35 %	n/a	4.35 %	6.71 %

(1) The discount rate used for operating leases is based on the Company's incremental borrowing rate at lease commencement and may be adjusted if modifications to lease terms or lease reassessments occur. The discount rate used for finance leases is based on the rates implicit in the leases.

The following table includes other quantitative information for the Company's leases *(in thousands)*:

	Years Ended December 31,	
	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Cash payments for operating leases	$ 778	$ 632
Cash payments for finance leases	70	130
Right-of-use assets obtained in exchange for new operating lease liabilities	—	—

Note 19. Subsequent Event

Chisholm Acquisition

On February 15, 2022, Earthstone, EEH, Chisholm Energy Operating, LLC ("OpCo") and Chisholm Energy Agent, Inc. ("Agent" and collectively with OpCo, "Chisholm"), as seller, consummated the transactions (the "Chisholm Closing") contemplated in the Chisholm Agreement. At the closing of the Chisholm Agreement, among other things, EEH acquired (the "Chisholm Acquisition") interests in oil and gas leases and related property of Chisholm located in Lea County and Eddy County, New Mexico, for aggregate consideration consisting of: (i) approximately $314.7 million in cash, net of preliminary and customary purchase price adjustments and remains subject to post-closing settlement between EEH and Chisholm paid at the closing of the Chisholm Acquisition, (ii) $70 million in cash to be paid as follows: $40 million to be paid six months after the closing of the Chisholm Acquisition and $30 million to be paid 12 months after the closing of the Chisholm Acquisition, subject to acceleration in the event that Earthstone receives gross proceeds of more than $450 million from a high yield bond offering or more than $50 million in gross proceeds from an offering of Class A Common Stock or preferred stock; and (iii) 19,417,476 shares of Class A Common Stock. On December 17, 2021, in accordance with the Chisholm Agreement and prior to the Chisholm Closing, Earthstone provided a deposit in the amount of $30.5 million which was recorded in Other noncurrent assets in the Consolidated Balance Sheeet as of December 31, 2021, as well as included in Acquisition of oil and gas properties in Cash flows from investing activities in the Consolidated Statements of Cash Flows for the year then ended. A Significant Shareholder was the majority owner of Chisholm as of the closing of the Chisholm Acquisition. A majority of the stockholders of Earthstone not affiliated with the Significant Shareholder approved the issuance of 19,417,476 shares of Class A Common Stock in connection with the closing of the Chisholm Acquisition.

Cash consideration for the Chisholm Acquisition was funded by borrowings under the Credit Agreement whose borrowing base was increased from $650 million to $825 million at the closing of the Chisholm Acquisition on February 15, 2022.

Bighorn Agreement

On January 30, 2022, Earthstone, EEH, and Bighorn Asset Company, LLC, a Delaware limited liability company ("Bighorn"), as seller, entered into a Purchase and Sale Agreement (the "Bighorn Agreement"). Pursuant to the Bighorn Agreement, EEH will acquire (the "Bighorn Acquisition") interests in oil and gas leases and related property of Bighorn located in the Midland Basin, Texas, for a purchase price (the "Bighorn Purchase Price") of $770 million in cash and 6,808,511 shares of Class A Common Stock. The Bighorn Purchase Price is subject to customary purchase price adjustments with an effective date of January 1, 2022. In connection with the Bighorn Agreement, EEH deposited $50 million in cash into a third-party escrow account as a deposit pursuant to the Bighorn Agreement, which will be credited against the Bighorn Purchase Price upon closing of the Bighorn Acquisition.

Credit Agreement

On January 30, 2022, Earthstone, EEH, as Borrower, Wells Fargo Bank, National Association ("Wells Fargo") as Administrative Agent, the lenders party thereto (the "Lenders") and the guarantors party thereto entered into an amended and restated Fifth Amendment (the "Amendment") to the Credit Agreement. Among other things, the Amendment increases the borrowing base and corresponding elected commitments from $650 million to $825 million upon the closing ("Chisholm Closing") of the Chisholm Agreement; provides that upon the closing of the Bighorn Acquisition (assuming the occurrence of the Chisholm Closing), the borrowing base and corresponding elected commitments will increase to $1.325 billion, unless Earthstone completes an unsecured senior notes offering (the "Notes Offering") prior to the closing of the Bighorn Acquisition in which case the elected commitments will be reduced by the amount of the net proceeds from a Notes Offering up to $500 million; provides for an increase in interest rates by 0.50% in the event a Notes Offering has not been completed prior to the closing of the Bighorn Acquisition; provides mechanics relating to the transition from LIBOR to a benchmark replacement rate to be effective contemporaneously with the effectiveness of the Amendment on January 30, 2022; adds certain hedging requirements relating to anticipated oil and natural gas production of the properties to be acquired pursuant to the Bighorn Acquisition; adjusts some financial covenants; redefines the limitations on certain restricted payments the Borrower may make; and makes certain administrative changes to the Credit Agreement.

Securities Purchase Agreement

On January 30, 2022, Earthstone entered into a securities purchase agreement (the "Securities Purchase Agreement") with EnCap Capital Energy Fund XI, L.P. ("EnCap Fund XI"), an affiliate of EnCap, and Cypress Investments, LLC, a fund managed by Post Oak Energy Capital, LP ("Post Oak" and collectively with EnCap Fund XI, the "Investors") to sell, in a private placement (the "Private Placement"), 280,000 shares of newly authorized convertible preferred stock, $0.001 par value per share (the "Preferred Stock"), each share of which will be convertible into 90.0900900900901 shares of Class A Common Stock for anticipated gross proceeds of $280.0 million, at a price of $1,000.00 per share of Preferred Stock (or $11.10 per share of Class A Common Stock on an as-converted basis). The Private Placement is contingent upon the closing of the Bighorn Acquisition. The Company intends to use the net proceeds from the sale of the Preferred Stock to partially fund the Bighorn Acquisition. As of the date of the Securities Purchase Agreement, EnCap and its affiliates beneficially owned approximately 46.5% of the outstanding voting power of Earthstone. Two of Earthstone's directors are employed by EnCap. The Securities Purchase Agreement and the Private Placement were evaluated and approved by the Audit Committee of the Board and unanimously approved by the Board.

Note 20. Supplemental Selected Quarterly Financial Data (Unaudited)

(In thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2021				
Oil and gas revenues	$ 75,572	$ 89,671	$ 110,384	$ 144,016
Income from operations	24,513	37,059	54,947	73,562
Net (loss) income attributable to Earthstone Energy, Inc.	(5,833)	(8,871)	10,418	39,770
Net (loss) income per common share attributable to Earthstone Energy, Inc.:				
Basic	$ (0.14)	$ (0.20)	$ 0.21	$ 0.76
Diluted	$ (0.14)	$ (0.20)	$ 0.20	$ 0.72
2020				
Oil and gas revenues	$ 45,138	$ 21,663	$ 41,047	$ 36,675
Loss from operations	(60,368)	(15,067)	(4,484)	(4,694)
Net income (loss) attributable to Earthstone Energy, Inc.	16,708	(16,339)	(5,445)	(8,471)
Net income (loss) per common share attributable to Earthstone Energy, Inc.:				
Basic and diluted	$ 0.57	$ (0.55)	$ (0.18)	$ (0.28)
2019				
Oil and gas revenues	$ 40,728	$ 44,542	$ 39,204	$ 66,788
Income from operations	10,444	12,348	9,564	22,776
Net (loss) income attributable to Earthstone Energy, Inc.	(17,204)	8,777	11,770	(2,624)
Net income (loss) per common share attributable to Earthstone Energy, Inc.:				
Basic and diluted	$ 0.60	$ 0.30	$ 0.41	$ (0.09)

First quarter 2020 loss from operations includes non-cash impairment charges of $42.8 million to the Company’s oil and natural gas properties, as well as a non-cash impairment charge of $17.6 million related to the Company’s goodwill. Third quarter 2020 loss from operations includes a non-cash impairment charge of $2.1 million to the Company’s oil and natural gas properties. Fourth quarter 2020 loss from operations includes a non-cash impairment charge of $2.0 million to the Company’s oil and natural gas properties. Impairments to oil and natural gas properties are discussed in *Note 7. Oil and Natural Gas Properties.*

Note 21. Supplemental Information On Oil And Gas Exploration And Production Activities (Unaudited)

Costs Incurred Related to Oil and Gas Activities

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural gas producing activities. Capitalized costs for proved properties include costs for oil and natural gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and natural gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion.

The Company's oil and natural gas activities for 2021, 2020 and 2019 were entirely within the United States of America. Costs incurred in oil and natural gas producing activities were as follows (*in thousands*):

	Years Ended December 31,		
	2021	2020	2019
Acquisition cost [1]:			
Proved	$ 465,144	$ —	$ (141)
Unproved	43	—	(125)
Exploration costs:			
Abandonment costs	—	—	653
Geological and geophysical	341	298	—
Development costs	134,035	67,550	210,520
Total additions	$ 599,563	$ 67,848	$ 210,907

(1) Acquisition costs incurred during 2019 consisted primarily of purchase price adjustments related to 2018 acquisitions.

During the years ended December 31, 2021, 2020 and 2019, additions to oil and natural gas properties of $2.2 million, $0.8 million and $0.1 million, respectively, were recorded for estimated costs of future abandonment related to new wells drilled or acquired.

During the years ended December 31, 2021, 2020 and 2019, the Company had no capitalized exploratory well costs, nor capitalized costs related to share-based compensation, general corporate overhead or similar activities.

Capitalized Costs

Capitalized costs, impairment, and depreciation, depletion and amortization relating to the Company's oil and natural gas properties producing activities, all of which are conducted within the continental United States as of December 31, 2021 and 2020, are summarized below (*in thousands*):

	December 31,	
	2021	2020
Oil and gas properties, successful efforts method:		
Proved properties	$ 1,726,019	$ 1,118,148
Accumulated impairment to proved properties	(100,652)	(100,652)
Proved properties, net of accumulated impairments	1,625,367	1,017,496
Unproved properties	289,341	301,083
Accumulated impairment to Unproved properties	(67,316)	(67,316)
Unproved properties, net of accumulated impairments	222,025	233,767
Land	5,382	5,382
Total oil and gas properties, net of accumulated impairments	1,852,774	1,256,645
Accumulated depreciation, depletion and amortization	(395,625)	(291,213)
Net oil and gas properties	$ 1,457,149	$ 965,432

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves represent estimated quantities expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The proved reserves estimates shown herein for the years ended December 31, 2021, 2020 and 2019 have been prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

The reserve information in these Consolidated Financial Statements represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the Company’s control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. As a result, estimates by different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company’s proved reserves will decline as reserves are produced.

The following table illustrates the Company’s estimated net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated. The oil prices as of December 31, 2021, 2020 and 2019 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate (“WTI”) spot prices which equates to $66.56 per barrel, $39.57 per barrel and $55.69 per barrel, respectively. The natural gas prices as of December 31, 2021, 2020 and 2019 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $3.60 per MMBtu, $1.99 per MMBtu and $2.58 per MMBtu, respectively. Natural gas liquids are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics. The natural gas liquids prices used to value reserves as of December 31, 2021, 2020 and 2019 averaged $30.16 per barrel, $11.61 per barrel and $16.17 per barrel, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials, resulting in the aforementioned oil, natural gas and natural gas liquids reserves as of December 31, 2021 being valued using prices of $65.64 per barrel, $3.01 per MMBtu and $30.16 per barrel, respectively. All prices are held constant in accordance with SEC guidelines.

A summary of the Company's changes in quantities of proved oil, natural gas and NGL reserves for the years ended December 31, 2021, 2020 and 2019 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Balance - December 31, 2018	59,034	113,217	20,943	98,847
Extensions and discoveries	3,598	4,476	721	5,065
Sales of minerals in place	(31)	(4)	(1)	(32)
Production	(3,086)	(4,760)	(1,022)	(4,902)
Revision to previous estimates	(6,865)	(4,939)	3,047	(4,642)
Balance - December 31, 2019	52,650	107,990	23,688	94,336
Extensions and discoveries	420	1,258	230	860
Production	(3,180)	(7,282)	(1,237)	(5,630)
Revision to previous estimates	(9,800)	9,249	(2,432)	(10,691)
Balance - December 31, 2020	40,090	111,215	20,249	78,875
Extensions and discoveries	7,016	49,846	6,532	21,856
Sales of minerals in place	(8)	(1)	—	(8)
Purchases of minerals in place	25,114	106,539	17,103	59,973
Production	(4,381)	(14,505)	(2,257)	(9,055)
Revision to previous estimates	(6,756)	31,787	(2,596)	(4,054)
Balance - December 31, 2021	61,075	284,881	39,031	147,587
Proved developed reserves:				
December 31, 2018	14,325	26,110	4,969	23,646
December 31, 2019	18,220	35,120	7,447	31,521
December 31, 2020	18,878	55,764	10,125	38,298
December 31, 2021	35,824	190,999	25,917	93,575
Proved undeveloped reserves:				
December 31, 2018	44,709	87,107	15,974	75,201
December 31, 2019	34,430	72,870	16,241	62,815
December 31, 2020	21,212	55,450	10,123	40,577
December 31, 2021	25,251	93,882	13,114	54,012

The table below presents the quantities of proved oil, natural gas and NGLs reserves attributable to noncontrolling interests as of December 31, 2021 and 2020:

As of December 31, 2021	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Proved developed	14,011	74,702	10,137	36,598
Proved undeveloped	9,876	36,719	5,129	21,125
Total proved	23,887	111,421	15,266	57,723

As of December 31, 2020	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Proved developed	10,113	29,873	5,424	20,516
Proved undeveloped	11,363	29,704	5,423	21,737
Total proved	21,476	59,577	10,847	42,253

As of December 31, 2019	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
Proved developed	9,933	19,146	4,060	17,183
Proved undeveloped	18,769	39,724	8,853	34,243
Total proved	28,702	58,870	12,913	51,426

Notable changes in proved reserves for the year ended December 31, 2021 included the following:

- *Extensions and discoveries.* In 2021, extensions and discoveries of 21.9 MMBoe were primarily the result of successful drilling results in the Midland Basin.
- *Purchases of mineral in place.* In 2021, the Company completed multiple acquisitions that resulted in 60.0 MMBoe in additional reserves, as disclosed above in *Note 3. Acquisitions and Divestitures*.
- *Revision to previous estimates.* In 2021, the downward revisions of prior reserves of 4.1 MMBoe consisted of changes in anticipated well densities and changes in performance and other economic factors totaling 9.2 MMBoe and 5.5 MMBoe, respectively, offset by a positive revision of 10.6 MMBoe related to changes in prices.

Notable changes in proved reserves for the year ended December 31, 2020 included the following:

- *Extensions and discoveries.* In 2020, total extensions and discoveries of 860.0 MBoe were primarily the result of successful drilling results in the Midland Basin.
- *Revision to previous estimates.* In 2020, the downward revisions of prior reserves of 10.7 MMBoe were composed of negative revisions due to the reclassification of 11.9 MMBoe of reserves from proved undeveloped to non-proved due to the SEC's five-year development rule and negative revisions of 2.7 MMBoe due to changes in price offset by revisions of 3.9 MMBoe related to changes in performance and other economic factors.

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- *Extensions and discoveries.* In 2019, total extensions and discoveries of 5.1 MMBoe were primarily the result of successful drilling results in the Midland Basin.
- *Sales of minerals in place.* Sales of minerals in place totaled 32.0 MBoe during 2019, resulting from the disposition of certain non-operated properties in the Midland Basin. See *Note 3. Acquisitions and Divestitures* in the *Notes to Consolidated Financial Statements.*
- *Revision to previous estimates.* In 2019, the downward revisions of prior reserves of 4.6 MMBoe were primarily due to reduced commodity prices.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lack sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and analogous producing wells for each area or field. PUD locations were limited to areas of uniformly high-quality reservoir properties, between existing commercial producers where the reservoir can, with reasonable certainty, be judged to be continuous with existing producers and contain economically producible oil and natural gas on the basis of available geoscience and engineering data.

Changes in PUD reserves for the years ended December 31, 2021, 2020 and 2019 were as follows (*in MBoe*):

Proved undeveloped reserves at December 31, 2018(1)	75,201
Conversions to developed	(10,254)
Extensions and discoveries	1,230
Revision to previous estimates	(3,362)
Proved undeveloped reserves at December 31, 2019 (2)	62,815
Conversions to developed	(8,200)
Revision to previous estimates	(14,038)
Proved undeveloped reserves at December 31, 2020 (3)	40,577
Conversions to developed	(8,274)
Extensions and discoveries	20,521
Purchases of minerals in place	11,577
Revision to previous estimates	(10,389)
Proved undeveloped reserves at December 31, 2021 (4)	54,012

(1) Includes 41,560 MBoe attributable to noncontrolling interests.

(2) Includes 34,243 MBoe attributable to noncontrolling interests.

(3) Includes 21,737 MBoe attributable to noncontrolling interests.

(4) Includes 21,125 MBoe attributable to noncontrolling interests.

2021 Changes in Proved Undeveloped Reserves

Conversions to developed. In the Company's year-end 2020 plan to develop its PUDs within five years, it was estimated that $41.1 million of capital would be expended in 2021 for the conversion of 13 gross / 10.5 net PUDs to add 6.7 MMBoe. In 2021, due to improved commodity prices, the Company spent $55.1 million to convert 16 gross / 13.1 net PUDs adding 8.3 MMBoe to developed.

Revision to previous estimates. Downward revisions of prior reserves of 10.4 MMBoe consisted of changes in anticipated well densities and changes in performance and other economic factors of 9.2 MMBoe and 2.9 MMBoe, respectively, offset by a positive revision of 1.7 MMBoe related to changes in prices.

2020 Changes in Proved Undeveloped Reserves

Conversions to developed. In the Company's year-end 2019 plan to develop its PUDs within five years, the Company estimated that $111.1 million of capital would be expended in 2020 for the conversion of 28 gross / 17.6 net PUDs to add 11.3 MMBoe. In 2020, due to unforeseeable conditions previously described, the Company spent $67.8 million to convert 18 gross / 10.3 net PUDs adding 8.2 MMBoe to developed.

Revision to previous estimates. The Company maintains a five-year development plan, reviewed annually to ensure capital is allocated to the wells that have the highest risk-adjusted rates of return within the Company's inventory of undrilled well locations. In response to lower commodity prices, the Company reduced the pace of activity in its five-year development plan. This resulted in the reclassification of 11.9 MMBoe of reserves from proved undeveloped to non-proved during the year ended December 31, 2020 due to the five-year development rule. Based on the Company's then-current acreage position, strip prices, anticipated well economics, and its development plans at the time these reserves were classified as proved, the Company's management believes the previous classification of these locations as proved undeveloped was appropriate. The remaining revisions of 2.1 MMBoe were primarily due to reduced commodity prices.

2019 *Changes in Proved Undeveloped Reserves*

Conversions to developed. In the Company's year-end 2018 plan to develop its PUDs within five years, the Company estimated that $103.8 million of capital would be expended in 2019 for the conversion of 30 gross / 12.3 net PUDs to add 9.9 MMBoe, which was consistent with the $111.5 million actually spent to convert 32 gross / 13.4 net PUDs adding 10.3 MMBoe to developed reserves.

Extensions and discoveries. Additionally, 1.2 MMBoe were added as extensions and discoveries due to successful drilling results on the Company's acreage positions because of the wells the Company drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to the Company's acreage.

Revision to previous estimates. Revisions of 3.4 MMBoe were primarily due to reduced commodity prices.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) has been developed utilizing FASB ASC Topic 932, *Extractives Activities – Oil and Gas* (“ASC 932”) procedures and based on oil and natural gas reserve and production volumes estimated by the Company’s third-party petroleum engineering firm. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and commodity prices will probably differ from those required to be used in these calculations;
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- A 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- Future net revenues may be subject to different rates of income taxation.

At December 31, 2021, 2020 and 2019, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Prices used to estimate reserves are included in *Oil and Natural Gas Reserves* above. Future production costs include per-well overhead expenses allowed under joint operating agreements, abandonment costs (net of salvage value), and a non-cancelable fixed cost agreement to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure at December 31, 2021, 2020 and 2019 is as follows (*in thousands*):

	December 31,		
	2021	**2020**	**2019**
Future cash inflows	$ 6,042,508	$ 1,902,073	$ 3,250,868
Future production costs	(1,641,130)	(633,248)	(1,027,464)
Future development costs	(470,008)	(285,088)	(628,692)
Future income tax expense	(381,663)	(35,557)	(58,824)
Future net cash flows	3,549,707	948,180	1,535,888
10% annual discount for estimated timing of cash flows	(1,731,335)	(487,327)	(746,311)
Standardized measure of discounted future net cash flows (1)	$ 1,818,372	$ 460,853	$ 789,577

(1) At December 31, 2021, 2020 and 2019, the portion of the standardized measure of discounted future net cash flows attributable to noncontrolling interests was $711.2 million, $246.9 million and $430.4 million, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure for the Company’s proved oil and natural gas reserves during each of the years in the three-year period ended December 31, 2021 (*in thousands*):

	December 31,		
	2021	**2020**	**2019**
Beginning of year	$ 460,853	$ 789,577	$ 959,452
Sales of oil and gas produced, net of production costs	(343,914)	(105,555)	(150,708)
Sales of minerals in place	14	14	(458)
Net changes in prices and production costs	1,346,851	(381,769)	(565,240)
Extensions, discoveries, and improved recoveries	216,583	14,644	127,182
Changes in income taxes, net	(185,757)	17,826	12,697
Previously estimated development costs incurred during the period	41,120	66,788	210,520
Net changes in future development costs	(104,223)	258,741	118,348
Purchases of minerals in place	465,187	—	—
Revisions of previous quantity estimates	(151,748)	(273,781)	(35,588)
Accretion of discount	76,121	81,999	107,432
Changes in timing of estimated cash flows and other	(2,715)	(7,631)	5,940
End of year (1)	$ 1,818,372	$ 460,853	$ 789,577

(1) At December 31, 2021, 2020 and 2019, the portion of the standardized measure of discounted future net cash flows attributable to noncontrolling interests was $711.2 million, $246.9 million and $430.4 million, respectively.

Exhibit 21.1

SUBSIDIARIES OF THE COMPANY

	Jurisdiction of Organization
Earthstone Operating, LLC	Texas
Earthstone Energy Holdings, LLC	Delaware
Lynden Energy Corp.	British Columbia, Canada
Lynden USA Inc.	Utah
Earthstone Permian LLC	Texas

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100
AUSTIN, TEXAS 78729-1707
512-249-7000

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FORT WORTH, TEXAS 76102-4987
817-336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Earthstone Energy, Inc. for the year ended December 31, 2021, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our reserves report dated January 4, 2022 into the Registration Statements on Form S-3 (File Nos. 333-260824, 333-258455, 333-254106, 333-254099, 333-224334, 333-218277, 333-213543 and 333-205466) and Form S-8 (File Nos. 333-258456, 333-240998, 333-227720, 333-221248 and 333-210734) filed with the U.S. Securities and Exchange Commission.

Sincerely,

/s/ W. Todd Brooker

W. Todd Brooker, P.E.
President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

March 9, 2022

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-260824, 333-258455, 333-254106, 333-254099, 333-224334, 333-218277, 333-213543 and 333-205466) and Form S-8 (Nos. 333-258456, 333-240998, 333-227720, 333-221248 and 333-210734) of Earthstone Energy, Inc. (the "Company"), of our reports dated March 9, 2022, relating to the consolidated financial statements of the Company and the effectiveness of internal control over financial reporting of the Company, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2021.

/s/ Moss Adams LLP

Houston, Texas
March 9, 2022

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert J. Anderson, certify that:

1. I have reviewed this annual report on Form 10-K of Earthstone Energy, Inc.;

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

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

4. The registrant's other certifying officer 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 the 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: March 9, 2022

/s/ Robert J. Anderson

Robert J. Anderson
President, Chief Executive Officer and Director

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tony Oviedo, certify that:

1. I have reviewed this annual report on Form 10-K of Earthstone Energy, Inc.;

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

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

4. The registrant's other certifying officer 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 the 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: March 9, 2022

/s/ Tony Oviedo

Tony Oviedo

Executive Vice President - Accounting and Administration

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Earthstone Energy, Inc. (the "Company") for the period ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert J. Anderson, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 9, 2022

/s/ Robert J. Anderson

Robert J. Anderson

President, Chief Executive Officer and Director

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Earthstone Energy, Inc. (the "Company") for the period ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Tony Oviedo, Executive Vice President – Accounting and Administration of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 9, 2022	/s/ Tony Oviedo
	Tony Oviedo
	Executive Vice President - Accounting and Administration

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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January 4, 2022

Geoff Vernon
Vice President of Reservoir Engineering and A&D
Earthstone Energy, Inc.
1400 Woodloch Forest Dr., Suite 300
The Woodlands, Texas 77380

Re: Evaluation Summary - SEC Price Case
Earthstone Energy, Inc. Interests
Total Proved Reserves
Certain Properties in Texas
As of December 31, 2021

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Mr. Vernon:

As you have requested, this report was completed on January 4, 2022 for the purpose of submitting our estimates of proved reserves and forecasts of economics attributable to the *Earthstone Energy, Inc.* ("Earthstone") interests. We evaluated 100% of Earthstone's reserves, which are made up of oil and gas properties in various counties within the State of Texas. This report utilized an effective date of December 31, 2021, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the Securities and Exchange Commission ("SEC"). This report was prepared for the inclusion as an exhibit in a filing made with the SEC. The results of this evaluation are presented in the accompanying tabulation, with a composite summary of the values presented below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	- Mbbl	33,306.4	2,518.3	35,824.7	25,250.5	61,075.2
Gas	- MMcf	184,239.2	6,759.8	190,999.0	93,881.5	284,880.5
NGL	- Mbbl	24,870.8	1,046.9	25,917.6	13,113.7	39,031.4
Net Revenue						
Oil	- M$	2,182,444.5	164,953.5	2,347,398.1	1,661,691.0	4,009,089.5
Gas	- M$	554,919.8	19,826.4	574,746.3	281,584.2	856,330.4
NGL	- M$	746,977.6	29,333.2	776,310.7	400,777.7	1,177,088.4
Severance Taxes	- M$	198,034.8	11,274.8	209,309.6	127,614.9	336,924.5
Ad Valorem Taxes	- M$	43,379.3	2,677.5	46,056.7	29,257.0	75,313.7
Operating Expenses	- M$	836,724.9	26,069.2	862,794.0	308,348.8	1,171,142.8
Abandonment Costs	- M$	53,213.2	358.7	53,571.8	4,176.4	57,748.2
Future Development Costs	- M$	0.0	14,950.0	14,950.0	455,058.0	470,008.0
Future Net Cash Flow (BFIT)	- M$	2,352,990.2	158,783.0	2,511,773.2	1,419,597.8	3,931,370.8
Discounted @ 10%	**- M$**	**1,283,777.9**	**87,918.8**	**1,371,696.9**	**644,989.1**	**2,016,686.1**

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital (development) costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the reserves by Cawley, Gillespie & Associates, Inc. ("CG&A").

The oil reserves include oil and condensate. Oil volumes and NGL volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Hydrocarbon Pricing

As requested for SEC purposes, the base oil and gas prices calculated for December 31, 2021 were $66.56/BBL and $3.598/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average 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. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2021 and the base gas price is based upon Henry Hub spot prices (Platts Gas Daily) during 2021. NGL prices were adjusted on a per-property basis and averaged 45.2% of the net oil price on a composite basis.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differential, treating cost, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $65.64 per barrel for oil, $3.01 per MCF for natural gas and $30.16 per barrel for NGL. All economic factors were held constant in accordance with SEC guidelines.

Future Development Costs, Expenses and Taxes

Capital expenditures (Future Development Costs), lease operating expenses and ad valorem tax values were forecast as provided by Earthstone. As you explained, the capital costs were based on the most current estimates, lease operating expenses were based on the analysis of historical actual expenses, operating overhead is included for non-operated properties and no credit or deduction is made for producing overhead paid to the company by other owners of the operated properties. Lease operating expenses are applied based on location, operatorship and wellbore orientation on a per-property or per-unit basis. Capital costs and lease operating expenses were held constant in accordance with SEC guidelines.

Severance tax rates were applied at normal state percentages of oil and gas revenue. Severance tax rates in certain instances, where authorized by taxing authorities, have severance tax abatements and were provided by your office and applied when appropriate.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Federal, state, and local laws and regulations, which are currently in effect and that govern the development and production of oil and natural gas, have been considered in the evaluation of proved reserves for this report. The possible effects of changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. These possible changes could have an effect on the reserves and economics. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

This evaluation includes six (6) developed non-producing properties and 87 proved undeveloped locations, all of which are commercial using required SEC pricing. The developed non-producing reserves include reactivations and drilled-but-uncompleted wells. Each of these commercial drilling locations proposed as part of Earthstone's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, Earthstone has indicated it has every intent to complete this development plan as scheduled. Furthermore, Earthstone has demonstrated that it has adequate company staffing, financial backing and prior development success to ensure this development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described on page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, including undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved undeveloped reserves. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

Miscellaneous

An on-site field inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined, nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. However, the estimated costs of plugging and abandoning wells have been included herein as provided.

The reserve estimates and forecasts were based upon interpretations of data furnished by Earthstone and available from our files. Ownership information and economic factors such as liquid and gas prices, price differentials and expenses were furnished by Earthstone. To some extent, information from public records was used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

Closing

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. This evaluation was supervised by W. Todd Brooker, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or *Earthstone Energy, Inc.* and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

/s/ W. Todd Brooker
W. Todd Brooker, P.E.
President

/s/ Robert P. Bergeron, Jr., P.E.
Robert P. Bergeron, Jr., P.E.
Reservior Engineer

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production historyaccumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method, which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for “resource plays,” where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method may also be applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained in this manner are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **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 a 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, includinggovernmental 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.

"(6) **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.

"(31) **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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves**. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).
reserves.

"(17) **Possible reserves**. Possible reserves are those additional reserves that are less certain to be recovered than probable

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S-K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted*, *but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

"(26) **Reserves**. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those

reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."