FORM 10-K

EARTHSTONE ENERGY INC - ESTE

Filed: March 12, 2019 (period: December 31, 2018)

Annual report with a comprehensive overview of the company

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2018

Or

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

Commission File No. 001-35049

EARTHSTONE Energy Inc.

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	**Name of each exchange on which registered**
Class A Common Stock, $0.001 par value per share	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 issuer (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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 and posted on its corporate Website, if any, 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 filed). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act (check one):

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 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 $8.85 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 $188,132,742.

As of March 8, 2019, 28,717,599 shares of the registrant's Class A Common Stock and 35,452,178 shares of Class B Common Stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for its 2019 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," "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 and weakness 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") and other oil and natural gas producing countries;
- 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;
- the risk of the actual presence or recoverability of oil and natural gas reserves and that future production rates will 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 developing, acquiring, discovering and producing oil and natural gas reserves;
- the 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 goods 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;
- 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;
- 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;
- 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, state and tribal 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 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.

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.

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.

Farm-in or ***Farm-out*** – An agreement whereby the owner of a working interest in an oil and natural gas lease assigns or contractually conveys, subject to future assignment, the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the farmee is required to drill one or more wells in order to earn its interest in the acreage. The farmor usually retains a royalty and/or an after-payout interest in the lease. The interest received by the farmee is a “farm-in” while the interest transferred by the farmor is a “farm-out.”

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.

HBP – Held by production, a mineral lease provision that extends the right to operate and maintain a lease as long as the property produces a minimum quantity of oil and/or natural gas.

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 Development Agreement or ***JDA*** – An agreement that provides for the joint development of a tract of land typically utilized after the leasing phase has concluded or when minerals are HBP.

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, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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. 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. 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. 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 (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period 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.

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. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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.

Slickwater – A method of hydraulic fracturing that predominately uses water and chemicals, with sand, that is injected into an oil or natural gas reservoir to create a fracture in the reservoir rock and create or enhance fluid flow.

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.

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 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. At present, our primary assets are located in the Midland Basin of west Texas and the Eagle Ford Trend of south Texas.

Our primary focus is concentrated in the Midland Basin of west Texas, a high oil and liquids rich resource basin which provides us with multiple horizontal targets with proven production results, long-lived reserves and historically high drilling success rates. During 2018, we used one drilling rig and successfully drilled 16 wells in the Midland Basin with an average working interest of 89%. We completed 19 Midland Basin wells during 2018, including three wells that came online at the end of December 2018. With 866 potential gross horizontal drilling locations in the Midland Basin, we are focused on developmental drilling and completion operations in the area. We currently plan to maintain a one-rig drilling program on our operated acreage in the Midland Basin and expect to drill approximately 16 wells in 2019. Additionally, we continue to pursue acreage trades in the southern Midland Basin with the intent of increasing our operated acreage and drilling inventory, drilling and completing longer laterals and realizing greater operating efficiency.

We also own certain assets in the Eagle Ford Trend of south Texas where we have locations in the Eagle Ford and Austin Chalk formations. During 2018, we drilled five Eagle Ford wells with an average working interest of 17% and completed 11 wells (five wells with a 17% working interest and six wells with a 25% working interest). We expect to drill seven wells, with an average working interest of 22%, in this area during 2019 and may consider additional drilling based on improvements in oil and natural gas commodity prices. We have 67 potential gross operated drilling locations in the Eagle Ford Trend for future development.

We have approximately 29,500 net acres in the core of the Midland Basin, of which 77% is operated and 23% is non-operated. Upon finalization of documents for an agreed-upon mineral lease in Reagan County, which is expected to occur in the first quarter of 2019, we will have approximately 30,200 net acres in the core of the Midland Basin. We hold an approximate 94% working interest in our operated acreage and an approximate 40% working interest in our non-operated acreage. Our operated acreage in the Midland Basin is primarily located in Reagan, Upton and Midland counties. Our non-operated acreage in the Midland Basin is located primarily in Howard, Glasscock, Martin, Midland and Reagan counties. In total, we have an interest in 192 gross producing wells in the Midland Basin. We have approximately 14,300 net leasehold acres in the Eagle Ford Trend, which primarily consists of approximately 14,100 operated net leasehold acres in the crude oil window in Fayette, Gonzales and Karnes counties, with working interests ranging from approximately 17% to 67%. We have an interest in 106 gross operated producing wells and six gross non-operated producing wells in the Eagle Ford Trend.

At December 31, 2018, our estimated proved oil and natural gas reserves were approximately 98,847 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, 2018, our proved reserve quantities were approximately 60% oil, 19% natural gas, 21% NGLs with 24% of those reserves classified as proved developed. The calculated percentages include proved developed non-producing reserves. Of these interests, approximately 54,628 MBOE are attributable to noncontrolling interests. See *Note 9. Noncontrolling Interest* in the Notes to Consolidated Financial Statements.

Our Business Strategy

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 Basin and increase stockholder value through the following:

- pursue value-accretive acquisition and corporate merger opportunities, which could increase the scale of our operations;
- profitably increase cash flows, production and reserves by selectively developing our acreage base;
- expand our acreage positions and drilling inventory in our areas of primary interest through acquisitions and farm-in opportunities, with an emphasis on operated positions;
- block up acreage to allow for 10,000-foot (or longer) horizontal lateral drilling locations which provide higher economic returns;
- maintain operating control over the majority of our production, development and undeveloped acreage; and

- maintain a strong balance sheet and financial flexibility.

Our Strengths

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

- extensive horizontal development potential in one of the most oil rich basins of the United States;
- experienced management team with substantial technical and operational expertise and a history of successful acquisition and merger transactions;
- operating control over the majority of our production and development activities; and
- conservative balance sheet.

Recent Developments

Terminated Contribution Agreement

As previously disclosed in our Current Report on Form 8-K filed on October 17, 2018 with the SEC, on October 17, 2018, Earthstone, Earthstone Energy Holdings, LLC ("EEH") and Sabalo Holdings, LLC ("Sabalo Holdings") entered into a contribution agreement (the "Contribution Agreement") which provided for the contribution by Sabalo Holdings of all its interests in Sabalo Energy, LLC ("Sabalo Energy") and Sabalo Energy, Inc. to EEH (the "Sabalo Acquisition"). On December 21, 2018, Earthstone, EEH and Sabalo Holdings entered into a termination agreement (the "Termination Agreement"), pursuant to which the parties mutually terminated the Contribution Agreement.

In connection with the Termination Agreement, Earthstone, EEH and Sabalo Holdings also agreed to release each other from certain claims and liabilities arising out of or related to the Contribution Agreement and the transactions contemplated therein or thereby. In addition, we estimated total transaction costs to be approximately $13.4 million, including payment to Sabalo Holdings of $1.6 million for reimbursement of its expenses. All other related agreements were also terminated in conjunction with the termination of the Contribution Agreement.

Midland Basin Acreage Trade

On October 5, 2018, we closed a transaction in the Midland Basin that included producing properties and undeveloped acreage (the "Exchange"). Under the terms of the Exchange, we acquired 3,899 net operated acres in Reagan County with virtually a 100% working interest, in exchange for 1,222 net non-operated acres in Glasscock County with an average working interest of 39% and $27.8 million in cash, subject to customary closing adjustments. The effective date of the transaction was September 1, 2018.

Along with the net increase of 2,677 acres, the Exchange also resulted in a net production increase of approximately 350 Boe/d. The producing wells acquired in the Exchange are connected into a third-party crude oil pipeline gathering system, which will assure flow capacity for this production as well as any volumes from future wells on this acreage. With these acreage acquisitions, our total net acreage in the Midland Basin increased to approximately 29,500 acres, of which approximately 22,800 acres are operated by us. For further discussion, see *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements included in this report. Upon finalization of documents for an agreed-upon mineral lease in Reagan County, which is expected to occur in the first quarter of 2019, we will have approximately 30,200 net acres in the core of the Midland Basin.

Bold Transaction

On May 9, 2017, Earthstone completed a 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 USA Inc., a Utah corporation ("Lynden US"), Lynden USA Operating, LLC, a Texas limited liability company ("Lynden Op"), Bold Energy Holdings, LLC, a Texas limited liability company ("Bold Holdings"), and Bold Energy III LLC, a Texas limited liability company ("Bold"). The purpose of the Bold Contribution Agreement was to provide for, among other things described below, the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of Texas (the "Bold Transaction").

The Bold Transaction was structured in a manner commonly known as an "Up-C." Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes - Class A common stock, $0.001 par value per share (the "Class A Common Stock"), and Class B common stock, $0.001 par value per share (the "Class B Common Stock"), and all of Earthstone's existing outstanding common stock, $0.001 par value per share (the "Common Stock"), was recapitalized on a one-for-one basis for Class A Common Stock (the "Recapitalization"); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the "Earthstone Assets") to EEH, in exchange for 16,791,296 membership units of EEH (the "EEH Units"); (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under Earthstone's 2014 Long-Term Incentive Plan, as amended (the "2014 Plan"), to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of 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 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.

Our Operations

We are currently the operator of properties containing approximately 82% of our proved oil and natural gas reserves and 86% of our proved PV-10 as of December 31, 2018 (see reconciliation of PV-10 to the standardized measure of discounted future net cash flows in Item 2. Properties). As operator, we manage and are able to directly influence development and production of operations 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 operating cost, production rates and reserves. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price 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.

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, 2018, three purchasers accounted for 27%, 11% and 10%, respectively, of our revenue during the period. For the year ended December 31, 2017, three purchasers accounted for 18%, 14% and 14%, 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 decided to stop 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 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 at i) our tank batteries and transport the oil by truck, or ii) at a pipeline delivery point. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems.

In addition, we generally move the majority of our produced salt water by pipeline connected to our operated salt water disposal wells or by pipeline to commercial disposal facilities.

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 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.

Seasonality of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas drilling 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 any 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 recent years, oil, natural gas and NGLs prices have been under considerable pressure due to oversupply and other market conditions. Specifically, increased foreign production and increased efficiencies in horizontal drilling, combined with exploration of newly developed shale fields in North America, have dramatically increased global oil and natural gas production, which has led to significantly lower market prices for these commodities. 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. 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 in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, while some states 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 affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

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 Natural Gas Liquids

The prices at which we sell oil, natural gas and natural gas liquids 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 natural gas liquids 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, natural gas liquids, 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 natural gas liquids 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. For example, in response to a lawsuit filed in the U.S. District Court for the District of Columbia by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and natural gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. EPA action in response to the consent decree remains pending. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. 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 rule defining the scope of federal jurisdiction over Waters of the United States (the "WOTUS rule") became effective; however, this rule has been stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit while the appellate court and numerous federal district courts consider lawsuits opposing implementation of the rule. The U.S. Supreme Court considered the issue of which court has jurisdiction to hear challenges to the WOTUS rule, and in January 2018 concluded that jurisdiction rests with the federal district courts. In addition, in 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to review the WOTUS rule and, if the agencies' reviews find that the rule does not meet the executive order's goal of promoting economic growth while reducing regulatory uncertainty, to initiate a new rulemaking to repeal or revise the rule. Pursuant to the executive order, in June 2017, the EPA and U.S. Army Corps of Engineers formally proposed to rescind the WOTUS rule. In January 2018, the EPA and the U.S. Army Corps of Engineers finalized a rule that would delay applicability of the WOTUS rule for two years, but a federal judge barred the agencies' suspension of the rule in August 2018. Separately, a federal court in Georgia enjoined implementation of the rule in 11 states. However, in December 2018, the EPA and the U.S. Army Corps released a proposed rule that would replace the WOTUS rule and significantly reduce the waters subject to federal regulation under the CWA. Such proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. The scope of the jurisdictional reach of the Clean Water Act will likely remain uncertain for several years.

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 salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. In Texas, the Texas Railroad Commission (" **RRC**") regulates the disposal of produced water by injection well. Permits must be obtained before drilling salt water 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. 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 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 at depths 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.

In addition, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. Also, on November 15, 2016, the BLM finalized a waste preventing rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the state of California filed lawsuits challenging the rule rescission. Also, on February 22, 2018, the BLM published proposed amendments to the waste prevention rule that would eliminate certain air quality provisions and, on April 4, 2018, a federal district court stayed certain provisions of the 2016 rule. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

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.

Some states and local jurisdictions in which we operate or hold oil and natural gas interests 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. 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. A number of 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.

Air Emissions

The federal Clean Air Act 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 Clean Air Act 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. In particular, 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, President Trump 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 June 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. On September 11, 2018, the EPA proposed targeted improvements to the rule, including amendments to the rule’s fugitive emissions monitoring requirements, and expects to “significantly reduce” the regulatory burden of the rule in doing so. 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. 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. In July 2018, the EPA finished issuing area designations with respect to ground-level ozone for U.S. counties as either “attainment/unclassifiable” or “unclassifiable.” 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.

Climate Change

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. Also, as noted above, the EPA has promulgated a New Source Performance Standard related to methane emissions from the oil and natural gas source category.

While Congress has considered legislation related to the reduction of GHG emissions in the past, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future 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.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. Currently, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

National Environmental Policy Act

Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

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 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 make a determination on listing of more than 250 species as endangered or threatened under the FSA 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 Migratory Bird Treaty Act. 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 Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially affect our operations. The federal government in the past has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. 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 the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes that regulate the protection of the health and safety of workers. 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 regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure 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 2017, nor do we anticipate that such expenditures will be material in 2018.

Employees

As of December 31, 2018, we had 65 full-time employees, of which nine are management, 19 are technical personnel, 19 are administrative personnel and 18 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 Leases

As of December 31, 2018, we leased office space as set forth in the following table:

Location	Approximate Size	Lease Expiration Date	Intended Use
The Woodlands, Texas	19,600 sq. ft.	December 31, 2019	Office
Midland, Texas	9,200 sq. ft.	June 30, 2019	Office

During 2018, aggregate rental payments for our office facilities totaled approximately $0.9 million.

Executive Officers of the Company

The following table sets forth, as of March 1, 2019, certain information regarding the executive officers of Earthstone:

Name	Age	Position
Frank A Lodzinski	69	Chairman of the Board and Chief Executive Officer
Robert J. Anderson	57	President
Tony Oviedo	65	Executive Vice President, Accounting and Administration
Mark Lumpkin, Jr.	45	Executive Vice President and Chief Financial Officer
Steven C. Collins	54	Executive Vice President, Completions and Operations
Timothy D. Merrifield	63	Executive Vice President, Geological and Geophysical
Francis M. Mury	67	Executive Vice President, Drilling and Development

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

Frank A. Lodzinski has served as our Chairman and Chief Executive Officer since December 2014. 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 45 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 compensation committee of Yuma Energy, Inc. since October 2016 and previously served on its audit committee from September 2014 to October 2016. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

Robert J. Anderson is a petroleum engineer with over 30 years of diversified domestic and international oil and gas experience. He has served as our 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 Earthstone 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. From September 2000 to February 2004, he was employed by Anadarko Petroleum Corporation as a petroleum engineer. In addition, he has worked with major oil companies, including ARCO International/Vastar Resources, and independent oil companies, including Hunt Oil, Hugoton Energy, and Pacific Enterprises Oil Company. His professional experience includes acquisition evaluation, reservoir and production engineering, field development, project economics, budgeting and planning, and capital markets. His domestic acquisition and divestiture experience includes Texas and Louisiana (offshore and onshore), Mid-Continent, and the Rocky Mountain states, and his international experience includes Canada, South America, and Russia. 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 21 years of experience including over 14 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 29 years of operations and related experience. He has served as our Executive Vice President, Completions and Operations 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 Earthstone in December 2014. Prior to employment by Oak Valley, he served from August 2012 to November 2012 as a consultant to Halcón. 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 38 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 Earthstone 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, Forcenergy, 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.

Francis M. Mury has over 43 years of oil and gas industry experience. He has served as our Executive Vice President, Drilling and Development 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 Earthstone in December 2014. Prior to employment by Oak Valley, he was employed by GeoResources, Inc. from April 2007 until its merger with Halcón in August 2012, ultimately serving as an Executive Vice President, Chief Operating Officer–Southern Region. He has held prior roles at AROC, Texoil, Hampton Resources, Wainoco Oil & Gas Company, Diasu Exploration Company, and Texaco, Inc. His experience extends to all facets of petroleum engineering, including reservoir engineering, drilling and production operations, petroleum economics, geology, geophysics, land, and joint operations. Geographical areas of experience include Texas and Louisiana (offshore and onshore), North Dakota, Montana, Mid-Continent, Florida, New Mexico, Oklahoma, Wyoming, Pennsylvania and Michigan. Mr. Mury graduated from Nicholls State University with a degree in Computer Science.

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. When considering an investment in our shares of Class A Common Stock, you 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.

Oil, natural gas and natural gas liquids 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 natural gas liquids 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 natural gas liquids has been volatile. For example, during the period from January 1, 2014 through December 31, 2018, the West Texas Intermediate ("WTI") spot price for oil declined from a high of $107.95 per Bbl in June 2014 to $26.19 per Bbl in February 2016. 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 $1.49 per MMBtu in March 2016. During 2018, WTI spot prices ranged from $44.48 to $77.41 per Bbl and the Henry Hub spot price of natural gas ranged from $2.49 to $6.24 per MMBtu. Likewise, natural gas liquids, 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 natural gas liquids we produce and our production levels depend on numerous factors beyond our control, including:

- worldwide and regional economic and financial conditions impacting global and regional 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 natural gas liquids producing countries and regions, including the current conflicts in the Middle East, as well as conditions in South America, Africa and Eastern Europe;
- 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 natural gas liquids 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;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, natural gas and natural gas liquids 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. Under the EEH Credit Agreement, our borrowing base is subject to semi-annual redeterminations (May 1 and November 1) and our lenders have the right to call for an interim determination of the borrowing base under certain circumstances. A sustained decline in oil, natural gas and natural gas liquids prices could adversely impact our borrowing base in future borrowing base redeterminations, which could trigger repayment obligations under the EEH 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 natural gas liquids gas prices may cause a decline in the market price of our shares.

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

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 have been required to, and 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 natural gas liquids 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 the EEH Credit Agreement as a result of a periodic borrowing base redetermination or otherwise 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 the EEH Credit Agreement or any other obligation if required as a result of a borrowing base redetermination.

Availability under the EEH Credit Agreement is currently subject to a borrowing base of $275.0 million. The borrowing base is subject to scheduled semiannual redeterminations (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 EEH Credit Agreement. Reductions in estimates of our oil, natural gas and natural gas liquids reserves may result in a reduction in our borrowing base under the EEH Credit Agreement (if prices are kept constant). Reductions in our borrowing base under the EEH 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 natural gas liquids 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, 2018, we had $78.8 million of borrowings outstanding under the EEH Credit Agreement. We may make further borrowings under the EEH Credit Agreement in the future. Any significant reduction in our borrowing base under the EEH 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 EEH 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 natural gas liquids 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.

A t December 31, 2018, approximately 76% of our estimated reserves were classified as proved undeveloped. The development of our estimated proved undeveloped reserves of 75,201 MBOE will require an estimated $963.1 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 EEH 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 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. The 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; however, actual capital expenditures may vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as 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.

You 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, 2018 and 2017, 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. 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 natural gas liquids 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 natural gas liquids 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.

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 additional drilling rigs, equipment, supplies, personnel and oilfield services 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. For example, the steel we use for pipes, valve fittings and other equipment is generally imported from other countries, and the price for steel has risen significantly in 2018 due at least in part to the 25% tariff imposed by United States on imported steel. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. 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 2019 capital expenditures with cash on hand, cash generated by operations, borrowings under the EEH 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 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 EEH Credit Agreement.

If our revenues or the borrowing base under the EEH 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 investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. Such developments could 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.

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 swaps, collars, puts and basis swaps. 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. 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 for additional information.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing, and trade execution; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

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

The oil and natural gas industry is highly competitive particularly in the Permian Basin of Texas 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 economic 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.

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. Further, the EPA completed a study finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, on March 26, 2015, the BLM published a final rule governing hydraulic fracturing on federal and Indian lands. Also, on November 15, 2016, the BLM finalized a waste preventing rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the state of California filed lawsuits challenging the rule rescission. Also, on February 22, 2018, the BLM published proposed amendments to the waste prevention rule that would eliminate certain air quality provisions and, on April 4, 2018, a federal district court stayed certain provisions of the 2016 rule. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations. Further, legislation to amend the SDWA to repeal the exemption for hydraulic fracturing (except when diesel fuels are used) from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of Congress. 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.

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. For example, in December 2016, the EPA released its final report regarding the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances such as water withdrawals for fracturing in times or areas of low water availability, surface spills during the management of fracturing fluids, chemicals or produced water, injection of fracturing fluids into wells with inadequate mechanical integrity, injection of fracturing fluids directly into groundwater resources, discharge of inadequately treated fracturing wastewater to surface waters, and disposal or storage of fracturing wastewater in unlined pits. The results of these studies could lead federal and state governments and agencies to develop and implement additional regulations. 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.

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 could adversely affect our ability to conduct drilling and production activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, which may cause a loss of production from temporary cessation of activity 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.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids we produce.

In response to findings that emissions of carbon dioxide, methane and other GHGs present a danger to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards for these emissions.

EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations.

Furthermore, in June 2016, the EPA finalized rules, known as Subpart OOOOa, that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. 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 methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

While Congress has from time to time considered legislation to reduce emissions of GHGs, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulation programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and gas we produce could also have the effect of lowering the value of our reserves.

Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference agreement reached in December 2015, which entered into force in November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. It should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to causation or contribution to the asserted damage, or to other mitigating factors.

Our oil, natural gas and natural gas liquids 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 natural gas liquids are primarily sold in two geographic markets in Texas 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 natural gas liquids, 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.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and natural gas exploration, development and production companies. Such legislative changes have included, but not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The Tax Cuts and Jobs Act of 2017 (the "TCJA") did not directly affect deductions currently available to the oil and natural gas industry but any future changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of 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 natural gas liquids, 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 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. This is more likely in areas with recent increased production, such as our Permian Basin area where we have significant development activities. 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 natural gas liquids 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.

We may use 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.

Non-operated properties are controlled by third parties that may not allow us to proceed with our planned capital expenditures. Activities on our operated properties could also be limited or subject to penalties.

We currently are not the operator of some of our existing properties and, therefore, may not be able to influence production operations or further development activities. Joint ownership is customary in the oil and natural gas industry and is generally conducted under the terms of a joint operating agreement ("JOA"), where one of the working interest owners is designated as the "operator" of the property. For non-operated properties, subject to the specific terms and conditions of the applicable JOA, if we disagree with the decision of a majority of working interest owners, we may be required, among other things, to postpone proposed activity or decline to participate in drilling and completing of wells. If we decline to participate, we might be forced to relinquish our interest through "in-or-out" elections or may be subject to certain non-consent penalties, as provided in a JOA. In-or-out elections may require a joint owner to participate or forever relinquish its position, typically only in specific wells or drilling units, although such relinquished positions could be of a larger scope. Non-consent penalties typically allow participating working interest owners to recover from the proceeds of production, if any, an amount equal to 200% to 500% of the non-participating working interest owner's share of the cost of such operations. Further, even for properties operated by us, there may be instances where decisions related to drilling, completion and operating cannot be made in our sole discretion. In such instances, we could be limited in our development operations and subject to penalties as specified above if we choose not to participate in operations proposed by a majority of working interest owners.

Because we cannot control activities on properties we do not operate, we cannot directly control the timing of exploration and development projects. 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 operator 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 or development activities. The success and timing of exploration, acquisition and development 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. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, as well as conduct reservoir modeling and reserve estimation for compliance reporting.

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 seismic and drilling information, estimate quantities of oil and natural gas reserves as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production and financial institutions are also dependent on digital technology. The technologies needed to conduct oil and natural gas exploration, development and production activities make certain information the target of theft or misappropriation.

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.

We are subject to litigation relating to Bold and the Bold Transaction, and we may be subject to additional litigation, any of which could adversely affect our business, financial condition and operating results.

Olenik v. Lodzinksi et al.: On June 2, 2017, Nicholas Olenik filed a purported shareholder class and derivative action in the Delaware Court of Chancery against Earthstone's Chief Executive Officer, along with other members of the Board, EnCap, Bold, Bold Holdings and OVR. The complaint alleges that Earthstone's directors breached their fiduciary duties in connection with the Bold Contribution Agreement. The Plaintiff asserts that the directors negotiated the Bold Transaction to benefit EnCap and its affiliates, failed to obtain adequate consideration for the Earthstone shareholders 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. The suit seeks unspecified damages and purports to assert claims derivatively on behalf of Earthstone and as a class action on behalf of all persons who held Common Stock up to March 13, 2017, excluding defendants and their affiliates. 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. Earthstone and each of the other defendants believe the claims are entirely without merit and they intend to mount a vigorous defense. The ultimate outcome of this suit is uncertain, and while Earthstone is confident in its position, any potential monetary recovery or loss to Earthstone cannot be estimated at this time.

Hurricanes, earthquakes and other natural disasters could have an adverse effect on our business, financial condition and results of operations.

Some of our properties are located in areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage our assets and disrupt our production of oil and natural gas. In the third quarter of 2017, Hurricane Harvey caused disruptions in our operations and, as of December 31, 2017, we had incurred $0.2 million in losses. For more information regarding the impact of Hurricane Harvey on operating results, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations." Natural disasters can similarly affect our facilities as well. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially.

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 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.

Upon the closing of the Contribution Agreement on May 9, 2017, we became a holding company and the sole manager of EEH and 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 EEH Units, including 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, Lynden Corp and Lynden US, 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 an agreement providing for our senior secured revolving credit facility (the "EEH 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.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements.

EnCap controls a majority of the combined voting power of all classes of our outstanding voting stock. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a controlled company. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

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

Holders of Class A Common Stock and 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 our Third Amended and Restated Certificate of Incorporation. EnCap may be deemed to beneficially own approximately 61.1% of our voting interests. As a significant stockholder, EnCap and certain of its 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 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 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 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 a controlling stockholder.

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. We cannot predict the size of future issuances of our Class A Common Stock or 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.

Bold Holdings 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, 2019, there were approximately 35.5 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 or its permitted transferees. Pursuant to 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. We also entered into a registration rights agreement pursuant to which the shares of Class A Common Stock which may be issued upon redemption or exchange of EEH Units and shares of Class B Common Stock, subject to certain limitations set forth therein, have been registered for subsequent offers and sales by Bold Holdings and its permitted transferees.

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. Our future dividend policy is within the discretion of our Board and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, and investment opportunities. In addition, the EEH 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 our Third Amended and Restated 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. 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. We have no current plans to issue any shares of preferred stock.

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

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. For instance, if our financial results are below the expectations of securities analysts and investors, the market price of our Class A Common Stock could decrease, perhaps significantly. Other factors that may affect the market price of our Class A Common Stock include:

- changes in oil and natural gas prices;
- actual or anticipated fluctuations in our quarterly results of operations;
- our liquidity;
- sales of Class A Common Stock by our stockholders;
- changes in our cash flow from operations or earnings estimates;
- publication of research reports about us or the oil and natural gas exploration and production industry generally;
- competition for, among other things, capital, acquisition of reserves, undeveloped land, and skilled personnel;
- increases in market interest rates that may increase our cost of capital;
- changes in applicable laws or regulations, court rulings, and enforcement and legal actions;
- changes in market valuations of similar companies;
- adverse market reaction to any indebtedness we may incur in the future;
- additions or departures of key management personnel;
- actions by our stockholders;
- commencement of or involvement in litigation;
- news reports relating to trends, concerns, technological or competitive developments, regulatory changes, and other related issues in our industry;

- speculation in the press or investment community regarding our business;
- political conditions in oil and natural gas producing regions of the world;
- general market and economic conditions; and
- domestic and international economic, legal, and regulatory factors unrelated to our performance.

In addition, U.S. securities markets have experienced significant price and volume fluctuations. These fluctuations often have been unrelated to the operating performance of companies in these markets. Market fluctuations and broad market, economic, and industry factors may negatively affect the price of our Class A Common Stock, regardless of our operating performance. Any volatility or a significant decrease in the market price of our Class A Common Stock could also negatively affect our ability to make acquisitions using Class A Common Stock. Further, if we were to be the object of securities class action litigation as a result of volatility in our Class A Common Stock price or for other reasons, it could result in substantial costs and diversion of our management's attention and resources, which could negatively affect our financial results.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

As of December 31, 2018, we are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"). Section 404 requires that we document and test our internal control over financial reporting and issue our management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm issue an attestation report on such internal control. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in our internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our Class A Common Stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

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

Our Third Amended and Restated Certificate of Incorporation provides for a classified board of directors, with each member serving a three-year term. Provisions in our Third Amended and Restated 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 our Third Amended and Restated Certificate of Incorporation, 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

We have an operated position of approximately 22,800 net acres in the core of the Midland Basin of west Texas across Reagan, Upton, and Midland counties with an average working interest of approximately 94%. As of December 31, 2018, we had 15 gross vertical and 51 gross horizontal operated producing wells. Current internal estimates indicate 500 potential gross, largely de-risked, operated drilling locations, the vast majority of which are in various benches of the Wolfcamp and the Spraberry formations. Of these 500 operated locations, 462 locations are expected to have an average working interest of 83%, whereas 38 locations are expected to be operated units where we hold an average working interest of approximately 35%. We are actively pursuing trades and acquisitions of additional acreage that may increase our working interest in these 38 locations as well as increase our operated acreage.

We also have a non-operated position of approximately 6,700 net acres in the Midland Basin of west Texas, located in Howard, Glasscock, Martin and Midland counties, Texas. As of December 31, 2018, we had an interest in 100 gross vertical and 26 gross horizontal non-operated producing wells with an average working interest of approximately 36%.

We have identified 366 potential gross horizontal non-operated drilling locations in various benches of the Wolfcamp and Spraberry formations with an estimated average working interest of approximately 25%.

Eagle Ford Trend

As of December 31, 2018, we held approximately 29,000 gross (14,100 net) operated leasehold acres 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. We serve as the operator with working interests ranging from approximately 17% to 67%.

As of December 31, 2018, we operated 93 gross Eagle Ford wells and 13 gross Austin Chalk wells and had non-operated interests in approximately five gross producing Eagle Ford wells and one gross producing Austin Chalk well. We have identified a total of 68 potential gross Eagle Ford drilling locations in this acreage. In addition, because our acreage position is prospective for the Austin Chalk and Upper Eagle Ford formations, 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, 2018, 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 *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, 2018, our estimated proved reserves totaled 98,847 MBOE and had a PV-10 value of approximately $1,008.5 million (see Non-GAAP Reconciliation below) and a Standardized Measure of Discounted Future Net Cash Flows of approximately $959.5 million, all of which relate to our properties in Texas. We incurred approximately $153.2 million in capital expenditures, primarily drilling and completion costs, during 2018. We expect to further develop our properties through additional drilling.

2018 Activity in Proved Reserves

From January 1, 2018 to December 31, 2018, our total estimated proved reserves increased 24% from 79,976 MBOE to 98,847 MBOE. Of that, estimated proved developed reserves increased 18% from 19,961 MBOE to 23,646 MBOE and estimated proved undeveloped reserves increased 25% from 60,015 MBOE to 75,201 MBOE. These increases are primarily attributable to our successful drilling efforts in the Midland Basin, acquisitions and trades during the year, as well as improved commodity prices.

Proved Reserves as of December 31, 2018

The below table sets forth a summary of our estimated crude oil, natural gas and natural gas liquids reserves as of December 31, 2018, 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, 2018. Proved reserves are estimated 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, 2018 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	13,917	25,063	4,774	22,869	23%	$ 739,383	$ 421,106	$ 400,625	$ —
PDNP	408	1,047	195	777	1%	24,497	14,630	13,919	407
PUD	44,709	87,107	15,974	75,201	76%	1,739,209	572,764	544,908	963,129
Total proved (1)	59,034	113,217	20,943	98,847	100%	$ 2,503,089	$ 1,008,500	$ 959,452	$ 963,536

(1) Includes 32.6 MMBbl of oil, 62.6 Bcf of natural gas and 11.6 MMBbl of NGLs reserves attributable to noncontrolling interests. Additionally, $557.4 million of PV-10 and $530.2 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 Reconciliation

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)	$ 1,008,500
Future income taxes, discounted at 10%	(49,048)
Standardized measure of discounted future net cash flows (2)	$ 959,452

(1) Includes $557.4 million attributable to noncontrolling interests.

(2) Includes $530.2 million attributable to noncontrolling interests.

Drilled But Uncompleted Wells

In order to achieve efficiencies from a pricing and logistics standpoint, our customary sequence of drilling and completion operations is to drill a group of wells and defer completion operations until all drilling operations for the group are concluded and then commence completion activities. See activities related to wells included in our proved developed reserves subsequent to December 31, 2018 below.

	Wells			
	Gross	Net	MBOE	PV10 ($000's)
Proved developed non-producing at December 31, 2018	6.0	2.5	777	$ 14,631
Began producing in February 2019	(2.0)	(1.0)	(703)	(13,617)
Remaining proved developed non-producing	4.0	1.5	74	$ 1,014

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 prices as of December 31, 2018 and 2017, are based on the respective 12-month unweighted average of the first of the month prices of the WTI spot prices which equates to $65.56 per barrel and $51.34 per barrel, respectively. The natural gas prices as of December 31, 2018 and 2017 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $3.10 per MMBtu and $2.98 per MMBtu, respectively. The natural gas liquids prices used to value reserves as of December 31, 2018 and 2017 averaged $28.81 per barrel and $22.59 per barrel, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. All prices are held constant in accordance with SEC guidelines.

A summary of our changes in quantities of proved oil, natural gas and NGLs reserves for the years ended December 31, 2018 and 2017 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Balance - December 31, 2016	7,111	20,401	1,540	12,051
Extensions and discoveries	19,558	29,644	6,264	30,763
Sales of minerals in place	(1,833)	(6,853)	(1)	(2,976)
Purchases of minerals in place	28,176	46,709	9,950	45,911
Production	(1,828)	(3,260)	(500)	(2,872)
Revision to previous estimates	(3,857)	4,447	215	(2,901)
Balance - December 31, 2017	47,327	91,088	17,468	79,976
Extensions and discoveries	10,148	17,673	3,116	16,209
Sales of minerals in place	(2,651)	(14,300)	(1,562)	(6,596)
Purchases of minerals in place	3,532	9,890	1,629	6,810
Production	(2,370)	(3,610)	(655)	(3,627)
Revision to previous estimates	3,048	12,476	947	6,075
Balance - December 31, 2018	59,034	113,217	20,943	98,847
Proved developed reserves:				
December 31, 2016	6,052	13,545	1,051	9,361
December 31, 2017	11,949	23,336	4,123	19,961
December 31, 2018	14,325	26,110	4,969	23,646
Proved undeveloped reserves:				
December 31, 2016	1,059	6,856	489	2,690
December 31, 2017	35,378	67,752	13,345	60,015
December 31, 2018	44,709	87,107	15,974	75,201

The table below presents the quantities of proved oil, natural gas and NGLs reserves attributable to noncontrolling interests as of December 31, 2018 and 2017:

As of December 31, 2018	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Proved developed	7,917	14,430	2,746	13,068
Proved undeveloped	24,709	48,140	8,828	41,560
Total proved	32,626	62,570	11,574	54,628

As of December 31, 2017	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Proved developed	6,775	13,232	2,338	11,318
Proved undeveloped	20,059	38,415	7,566	34,028
Total proved	26,834	51,647	9,904	45,346

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* In 2018, total extensions and discoveries of 16.2 MMBOE was a result of successful drilling results and well performance primarily related to the Midland Basin.
- *Sales of minerals in place.* Sales of minerals in place totaled 6.6 MMBOE during 2018, which consisted of 4.7 MMBOE resulting from the disposition of non-operated properties in the Midland Basin as part of an acreage trade and 1.9 MMBOE related to the disposition of non-operated Eagle Ford properties, both further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

- *Purchases of minerals in place.* In 2018, total purchases of minerals in place of 6.8 MMBOE were primarily attributable to developed non-producing wells and undeveloped acreage acquired in the Midland Basin as part of an acreage trade, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Revision to previous estimates.* In 2018, the upward revisions of prior reserves of 6.1 MMBOE consisted of improved PUD reserves of 5.8 MMBOE with improved proved developed reserves of 0.3 MMBOE. PUD revisions are a result of our successful drilling efforts in the Midland Basin as well as improved commodity prices.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 30,763 MBOE was a result of successful drilling results and well performance primarily related to the Midland Basin. The closing of the Bold Transaction in May 2017 which included primarily operated acreage in the Midland Basin was a significant contributor to this.
- *Sales of minerals in place.* Sales of minerals in place totaled 2,976 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2017, total purchases of minerals in place of 45,911 MBOE were primarily attributable to the Bold Transaction, whereby we acquired interests in 63 producing oil and natural gas wells, developed non-producing wells and undeveloped acreage in the Midland Basin, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Revision to previous estimates.* In 2017, the downward revisions of prior reserves of 2,901 MBOE consisted of negative revisions to PUD reserves of 4,832 MBOE with improved proved developed reserves of 1,931 MBOE. PUD revisions are a result of (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. Positive revisions are primarily a result of increased oil and natural gas prices during 2017.

Proved Undeveloped Reserves

Proved undeveloped reserves ("PUDs") increased from 60,015 MBOE to 75,201 MBOE or 25%, for the year ended December 31, 2018 compared to the year ended December 31, 2017. PUDs represent 76% 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. In accordance with our 2018 year-end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within the next five years.

Changes in our PUD reserves for the years ended December 31, 2018 and 2017 were as follows (*in MBOE*):

Proved undeveloped reserves at January 1, 2017	2,690
Conversions to developed	(2,756)
Extensions and discoveries	27,977
Sales of minerals in place	(391)
Purchases of minerals in place	37,327
Revision to previous estimates	(4,832)
Proved undeveloped reserves at December 31, 2017 (1)	60,015
Conversions to developed	(4,419)
Extensions and discoveries	13,734
Sales of minerals in place	(4,702)
Purchases of minerals in place	4,735
Revision to previous estimates	5,838
Proved undeveloped reserves at December 31, 2018 (2)	75,201

(1) Includes 34,029 MBOE attributable to noncontrolling interests.

(2) Includes 41,560 MBOE attributable to noncontrolling interests.

2018 Changes in Proved Undeveloped Reserves

Conversions to developed. In our year-end 2017 plan to develop our PUDs within five years, we estimated that $51.9 million of capital would be expended in 2018 and that it would convert 4.3 MMBOE, which was consistent with the $55.4 million actually spent to convert 4.4 MMBOE to developed.

Extensions and discoveries. Additionally, 13.7 MMBOE were added as extensions and discoveries due to successful drilling results on our acreage positions because of the wells we drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to our acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 4.7 MMBOE during 2018, which consisted of 3.7 MMBOE resulting from the disposition of non-operated properties in the Midland Basin as part of an acreage trade and 1.0 MMBOE related to the disposition of non-operated Eagle Ford properties, both further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Purchases of minerals in place. In 2018, purchases of minerals in place of 4.7 MMBOE were attributable to developed non-producing wells and undeveloped acreage acquired in the Midland Basin as part of an acreage trade, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Revision to previous estimates. Revisions of 5.8 MMBOE were primarily due to our successful drilling efforts in the Midland Basin as well as improved commodity prices.

2017 Changes in Proved Undeveloped Reserves

Conversions to developed. In our year-end 2016 plan to develop our PUDs within five years, we estimated that $6.9 million of capital would be expended in 2017 and that it would convert 732 MBOE. Because of the improvement in commodity prices and the change in its development plan for 2017, we actually spent $8.5 million to convert 622 MBOE to developed. Our plan changed in that we developed more oil PUDs and elected not to participate in natural gas PUDs which included the above mentioned 443 MBOE associated with the Eagle Ford non-participation. The capital to develop our oil PUDs was higher on a per unit basis than the natural gas PUDs however the margins are higher for oil PUDs. The oil PUDs further benefited our longer-term operated development plans. Since the Bold Transaction closed in May 2017, the associated capital plan for the properties acquired in the Bold Transaction during 2017 was not considered in our year-end 2016 report. We did however incur $63.4 million to convert 2,134 MBOE of purchased PUD reserves to developed.

Extensions and discoveries. Additionally, 27,977 MBOE were added as extensions and discoveries due to successful drilling results on our acreage positions because of the wells we drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to our acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 391 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* to the Notes to Consolidated Financial Statements

Purchases of minerals in place. During 2017, 37,327 MBOE were added to PUD reserves upon the closing of the Bold Transaction.

Revision to previous estimates. Revisions of 4,832 MBOE were primarily due to (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon the closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. This non-participation has no impact on our ability to participate in future wells in this acreage position.

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, 2018 (*$ 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
2019	1,062	$ 56,535	$ 6,043	$ 124,864	$ (74,372)
2020	3,459	174,328	20,372	251,365	(97,409)
2021	6,585	320,411	38,097	287,984	(5,671)
2022	8,794	416,045	50,573	298,916	66,556
2023	7,457	331,444	42,643	—	288,802
Thereafter	47,844	2,082,720	521,417	—	1,561,303
Total	75,201	$ 3,381,483	$ 679,145	$ 963,129	$ 1,739,209

(1) Beginning in 2019 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) $61.18 per Bbl (WTI-Cushing spot prices, adjusted for differentials) and (ii) $2.13 per Mcf (Henry Hub spot natural gas price), as adjusted for location and quality by property.

Historically, our drilling programs have been substantially funded from our cash flow and borrowings under our credit facility. 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 EEH Credit Agreement. In addition, historically, we have been able to take advantage of the capital markets, as needed, when opportunities arose.

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 Mr. 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.

Robert J. Anderson, our President, 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 Petroleum Engineering from the University of Wyoming in 1986; a Master of Business Administration degree from the University of Denver in 1988; member of the Society of Petroleum Engineers since 1985; and more than 32 years of practical experience in estimating and evaluating reserve information with more than fifteen 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 over financial reporting, 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 our President. 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 Natural Gas Liquids Production, Average Price and Average Production Cost

The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2018 and 2017, the average sales price per unit sold and the average production cost per unit are presented below:

	Years Ended December 31,	
	2018	2017
Sales Volumes:		
Oil (MBbl)	2,370	1,828
Natural gas (MMcf)	3,610	3,260
Natural gas liquids (MBbl)	655	500
Barrels of oil equivalent (MBOE)*	3,627	2,872
Average daily production (BOE per day)	9,937	7,869
Average prices realized:**		
Oil (per Bbl)	$ 59.40	$ 48.43
Natural gas (per Mcf)	$ 2.05	$ 2.69
Natural gas liquids (per Bbl)	$ 26.23	$ 21.51
Barrels of oil equivalent (per BOE)	$ 45.59	$ 37.63
Production cost per BOE	$ 5.66	$ 6.84

* 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 2018 and 2017 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 natural gas liquids produced and sold by us, the average sales price per unit sold and the average production cost per unit for each of our core areas for the years ended December 31, 2018 and 2017.

Midland Basin

	Years Ended December 31,	
	2018	2017
Sales Volumes:		
Oil (MBbl)	1,835	1,059
Natural gas (MMcf)	3,080	1,821
Natural gas liquids (MBbl)	571	351
Barrels of oil equivalent (MBOE)*	2,920	1,714
Average daily production (BOE per day)	7,999	6,639
Average prices realized:**		
Oil (per Bbl)	$ 56.96	$ 48.42
Natural gas (per Mcf)	$ 1.89	$ 2.49
Natural gas liquids (per Bbl)	$ 26.38	$ 23.01
Barrels of oil equivalent (per BOE)	$ 42.95	$ 37.29
Production cost per BOE	$ 4.57	$ 4.65

* 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,	
	2018	2017
Sales Volumes:		
Oil (MBbl)	535	535
Natural gas (MMcf)	530	772
Natural gas liquids (MBbl)	84	94
Barrels of oil equivalent (MBOE)*	707	758
Average daily production (BOE per day)	1,937	2,077
Average prices realized:**		
Oil (per Bbl)	$ 67.78	$ 49.86
Natural gas (per Mcf)	$ 2.98	$ 3.09
Natural gas liquids (per Bbl)	$ 25.20	$ 18.52
Barrels of oil equivalent (per BOE)	$ 56.49	$ 40.65
Production cost per BOE	$ 10.11	$ 8.80

* 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, 2018. A net well represents our percentage of ownership of a gross well.

	Oil		Natural Gas		Total	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Midland Basin	190	104	2	1	192	105
Eagle Ford Trend	112	48	—	—	112	48

Acreage

The following table summarizes our gross and net developed and undeveloped acreage by state as of December 31, 2018. Net acreage represents our percentage ownership of gross acreage.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas	29,240	14,442	41,394	29,338	70,634	43,780

The following table summarizes, as of December 31, 2018, the portion of our gross and net acreage subject to expiration over the next three years if not successfully developed or renewed.

	Expiring Acreage							
	2019		2020		2021		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	1,002	716	598	406	40	10	1,640	1,132
Eagle Ford Trend	1,858	929	313	156	384	192	2,555	1,277
Total	2,860	1,645	911	562	424	202	4,195	2,409

We have development agreements related to certain of our operated leases in the Midland Basin which require us to drill 30 gross wells (30 net wells) over the next five years. If we do not drill the required wells, we would be in default of the agreements. All of the aforementioned wells are included in management's five-year development plan. Approximately 75% of the Midland Basin net acreage is held by production and approximately 86% of the Eagle Ford net acreage is held by production. On a combined basis, our total net acreage is approximately 79% held by production.

Exploratory Wells and Development Wells

Set forth below for the two years ended December 31, 2018 is information concerning the number of wells we drilled during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
Year	Productive	Dry	Productive	Dry	Drilled
2018	—	—	20	—	20
2017	—	—	11	—	11

Present Activities

As of March 1, 2019, we had two gross (1.3 net) operated wells and nine gross (0.9 net) non-operated wells in the process of drilling or completing.

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, 2018, 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. 16. 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 for Common Stock

Shares of our Class A Common Stock are listed on the NYSE under the symbol "ESTE." The following table sets forth the reported high and low sales prices of our Class A Common Stock for the periods indicated:

	Class A Common Stock Price	
Period	**High**	**Low**
2018		
First Quarter	$ 12.16	$ 9.01
Second Quarter	$ 10.85	$ 7.80
Third Quarter	$ 11.00	$ 7.45
Fourth Quarter	$ 10.19	$ 4.21
2017		
First Quarter	$ 15.50	$ 11.26
Second Quarter	$ 15.00	$ 9.07
Third Quarter	$ 11.68	$ 8.49
Fourth Quarter	$ 11.13	$ 7.85

Holders

As of March 1, 2019, there were approximately 3,000 holders of record of our Class A Common Stock and approximately 22 holders of record of our Class B Common Stock. There is no public market for our Class B Common Stock.

Dividends

We have never paid dividends on our Class A Common Stock or Class B Common Stock and do not intend to pay a dividend in the foreseeable future. Furthermore, the EEH 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 2018	—	—	—	—
November 2018	—	—	—	—
December 2018	26,956	$ 4.59	—	—

(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.

Item 6. Selected Financial Data

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

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.

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. At present, our assets are located in the Midland Basin of west Texas and the Eagle Ford Trend of south Texas.

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).

Areas of Operation

Our primary focus is concentrated in the Midland Basin of west Texas, a high oil and liquids rich resource which provides us with multiple horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates.

Midland Basin

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

We have been operating a one drilling rig program in the Midland Basin and plan to maintain a one rig program throughout 2019. In January 2019, we concluded drilling the second well on a two-well pad in Upton County and moved the rig to Midland County to drill five wells in our Mid-States Unit. We began completing three wells in February 2019 and expect to begin completing the five Mid-States wells in June 2019.

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.

Eagle Ford Trend

We drilled five wells in southern Gonzales County, Texas in 2018 and completed 11 wells in the area during the year. We expect to drill seven wells in this area during 2019 and may consider additional drilling based on improvement in the commodity prices.

Terminated Contribution Agreement

As previously disclosed in our Current Report on Form 8-K filed on October 17, 2018 with the SEC, on October 17, 2018, Earthstone, EEH and Sabalo Holdings entered into the Contribution Agreement which provided for the Sabalo Acquisition. On December 21, 2018, Earthstone, EEH and Sabalo Holdings entered into the Termination Agreement, pursuant to which the parties mutually agreed to terminate the Contribution Agreement.

In connection with the Termination Agreement, Earthstone, EEH and Sabalo Holdings also agreed to release each other from certain claims and liabilities arising out of or related to the Contribution Agreement and the transactions contemplated therein or thereby. In addition, we estimated total transaction costs to be approximately $13.4 million, including payment to Sabalo Holdings of $1.6 million for reimbursement of expenses. All other related agreements were also terminated in conjunction with the termination of the Contribution Agreement.

Midland Basin Acreage Trade

On October 5, 2018, we closed the Exchange. Under the terms of the Exchange, we acquired 3,899 net operated acres in Reagan County with virtually a 100% working interest, in exchange for 1,222 net non-operated acres in Glasscock County with an average working interest of 39% and $27.8 million in cash, plus customary closing adjustments. The effective date of the transaction was September 1, 2018.

Along with the net increase of 2,677 acres, the trade also resulted in a net production increase of approximately 350 Boe/d. The producing wells acquired in this trade are connected into a third-party crude oil pipeline gathering system, which will assure flow capacity for this production as well as any volumes from future wells on this acreage. For further discussion, see *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements included in this report.

Bold Transaction

On May 9, 2017, Earthstone completed the Bold Contribution Agreement. The purpose of the Bold Contribution Agreement was to provide for, among other things described below, the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of Texas (the “Bold Transaction”).

The Bold Transaction was structured in a manner commonly known as an “Up-C.” Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes - Class A Common Stock and Class B Common Stock, and all of Earthstone’s existing outstanding Common Stock, was recapitalized on a one-for-one basis for Class A Common Stock (the “Recapitalization”); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the “Earthstone Assets”) to EEH, in exchange for 16,791,296 EEH Units; (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under the 2014 Plan, to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of Class A Common Stock.

Results of Operations

Year ended December 31, 2018 compared to the year ended December 31, 2017

	Years Ended December 31,		
	2018	2017	Change
Sales volumes:			
Oil (MBbl)	2,370	1,828	30 %
Natural gas (MMcf)	3,610	3,260	11 %
Natural gas liquids (MBbl)	655	500	31 %
Barrels of oil equivalent (MBOE) (1)	3,627	2,872	26 %
Average daily production (BOE per day)	9,937	7,869	26 %
Average prices realized: (2)			
Oil (per Bbl)	$ 59.40	$ 48.43	23 %
Natural gas (per Mcf)	$ 2.05	$ 2.69	(24)%
Natural gas liquids (per Bbl)	$ 26.23	$ 21.51	22 %
(In thousands)			
Oil revenues	$ 140,775	$ 88,536	59 %
Natural gas revenues	7,396	8,777	(16)%
Natural gas liquids revenues	17,185	10,765	60 %
Total revenues	$ 165,356	$ 108,078	53 %
Lease operating expense	$ 20,522	$ 19,658	4 %
Severance taxes	$ 8,060	$ 6,060	33 %
Impairment expense	$ 4,581	$ 72,191	NM
Depreciation, depletion and amortization	$ 47,568	$ 36,915	29 %
General and administrative expense (excluding stock-based compensation)	$ 21,088	$ 20,466	3 %
Stock-based compensation	$ 7,071	$ 6,601	7 %
General and administrative expense	$ 28,159	$ 27,067	4 %
Transaction costs	$ 13,524	$ 4,732	NM
Gain on sale of oil and gas properties, net	$ 1,919	$ 9,105	NM
Interest expense, net	$ (2,898)	$ (2,699)	7 %
Write-off of deferred financing costs	$ —	$ (526)	NM
Gain (loss) on derivative contracts, net	$ 60,947	$ (7,986)	NM
Litigation settlement	$ (4,675)	$ —	NM
Income tax (expense) benefit	$ (2,470)	$ 16,373	NM

(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).

(2) Prices presented exclude any effects of oil and natural gas derivatives.

NM – Not meaningful

Oil revenues

For the year ended December 31, 2018, oil revenues increased by approximately $52.2 million or 59% relative to the comparable period in 2017. Of the increase, approximately $20.0 million was attributable to an increase in our realized price and $32.2 million was attributable to increased volume. Our average realized price per Bbl increased from $48.43 for the year ended December 31, 2017 to $59.40 or 23% for the year ended December 31, 2018. We had a net increase in the volume of oil sold of 542 MBbls or 30%, primarily due to the Bold properties acquired on May 9, 2017 representing a partial prior year, partially offset by the impact of non-core asset divestitures that took place in the third and fourth quarters of 2017.

Natural gas revenues

For the year ended December 31, 2018, natural gas revenues decreased by $1.4 million or 16% relative to the comparable period in 2017. Of the decrease, approximately $2.1 million was attributable to a decrease in our realized price, partially offset by an increase of $0.7 million attributable to increased volume. Our average realized price per Mcf decreased from $2.69 for the year ended December 31, 2017 to $2.05 or 24% for the year ended December 31, 2018. The total volume of natural gas produced and sold increased 350 MMcf or 11% primarily due to increased production at our Midland Basin properties as well as the impact of the timing of the Bold Transaction, partially offset by the impact of non-core asset divestitures that took place in the third and fourth quarters of 2017.

Natural gas liquids revenues

For the year ended December 31, 2018, natural gas liquids revenues increased by $6.4 million or 60% relative to the comparable period in 2017. Of the increase, approximately $2.3 million was attributable to an increase in our realized price and $4.1 million was attributable to increased volume. The volume of natural gas liquids produced and sold increased by 155 MBbls or 31%, primarily due to the timing of the Bold Transaction which substantially increased our Midland Basin properties on May 9, 2017, partially offset by the impact of non-core asset divestitures that took place in the third and fourth quarters of 2017.

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, ad valorem taxes and overhead charges provided for in operating agreements.

LOE increased by $0.9 million or 4% for the year ended December 31, 2018 relative to the comparable period in 2017. The increase in LOE was due to a $1.9 million increase related to the Bold properties acquired on May 9, 2017 representing a partial prior year and a $4.4 million increase related to the increased number of producing wells resulting from our 2018 drilling program, offset by a $5.4 million decrease related to non-core asset divestitures that took place in the third and fourth quarters of 2017.

Severance taxes

Severance taxes for the year ended December 31, 2018 increased by $2.0 million or 33% relative to the comparable period in 2017, primarily due to the increased prices of oil and natural gas liquids, partially offset by the impact of non-core asset divestitures that took place in the third and fourth quarters of 2017. However, as a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes remained flat when compared to the prior year period.

Impairment

During the year ended December 31, 2018, we recorded non-cash asset impairments of $4.6 million to our unproved oil and natural gas properties resulting from certain acreage expirations related to our Eagle Ford Trend properties. During the year ended December 31, 2017, we recognized $72.2 million of non-cash asset impairments as a result of significant forward commodity price declines and the recording of certain acreage expirations that negatively impacted our results of operations and equity. These impairments consisted of $63.1 million to our proved oil and natural gas properties and $9.1 million to our unproved oil and natural gas properties, primarily to our properties located in the Eagle Ford Trend. 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, 2018 by $10.7 million, or 29% relative to the comparable period in 2017, due to the addition of the assets acquired in the Bold Transaction to the depletable base, as well as increased production volumes, partially offset by the impact of non-core asset divestitures that took place in the third and fourth quarters of 2017.

General and administrative expense ("G&A")

These expenses consist primarily of employee remuneration, professional and consulting fees and other overhead expenses. G&A increased by $1.1 million for the year ended December 31, 2018 relative to the comparable period in 2017, primarily due to the increase to 65 full-time employees from the prior year-end amount of 58, as well as additional employee bonus amounts resulting from the improved commodity price environment.

Transaction costs

For the year ended December 31, 2018, transactions costs consisted of $13.5 million, primarily associated with the proposed Sabalo Acquisition terminated in December 2018. During the year ended December 31, 2017, we recorded $4.7 million in transaction costs primarily associated with the Bold Transaction completed in May 2017. See *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Interest expense, net

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Interest expense for the year ended December 31, 2018 was $2.9 million compared to $2.7 million for the comparable period in 2017. The $0.2 million increase in interest expense was primarily due to higher average borrowings outstanding compared to the prior year period. See *Note 13. Long-Term Debt* in the Notes to Consolidated Financial Statements.

Gain on sale of oil and gas properties, net

During the year ended December 31, 2018, we sold certain non-core oil and gas properties including our non-operated Eagle Ford assets located in south Texas, recording gains totaling $1.9 million. During the year ended December 31, 2017, we sold all of our oil and natural gas leases, oil and natural gas wells and associated assets located in the Williston Basin in North Dakota. We also sold certain of our non-core oil and natural gas properties in Texas, Montana, Oklahoma and North Dakota. In connection with these sales, we recorded gains totaling $9.1 million. See *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Gain (loss) on derivative contracts, net

For the year ended December 31, 2018, we recorded a net gain on derivative contracts of $60.9 million, consisting of unrealized mark-to-market gains of $76.0 million, partially offset by net realized losses on settlements of $15.1 million. For the year ended December 31, 2017, we recorded a net loss on derivative contracts of $8.0 million, consisting of unrealized mark-to-market losses of $7.3 million and net realized losses on settlements of $0.7 million.

Litigation Settlement

For the year ended December 31, 2018, we recorded an expense of $4.7 million related to the settlement of certain litigation. See *Note 16. Commitments and Contingencies* in the Notes to Consolidated Financial Statements.

Income tax (expense) benefit

During the year ended December 31, 2018, we recorded total income tax expense of $2.5 million which included (1) deferred income tax expense for Lynden US of $1.9 million as a result of its share of the distributable income from EEH, offset by a $0.5 million discrete income tax benefit related to refundable AMT tax credits resulting from the TCJA, (2) deferred income tax expense for Earthstone of $7.4 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 $1.1 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, 2018.

During the year ended December 31, 2017, we recorded a total income tax benefit of $16.4 million which included (1) income tax benefit of $8.6 million, of which $4.8 million related to the reduction of that amount in its deferred tax liability resulting from the federal corporate income tax rate reduction to 21%, (2) a $7.7 million income tax benefit for Earthstone as a discrete item during the current reporting period, which resulted from a change in assessment of the realization of its net deferred tax assets due to the deferred tax liability that was recorded with respect to its investment in EEH as part of the Bold Transaction as an adjustment to Additional paid-in capital in the Consolidated Statement of Equity, and (3) income tax expense of $12.6 million related to the reduction of the amount in its deferred tax asset resulting from the federal corporate income tax rate reduction to 21% which was fully offset by the reduction in its valuation allowance for that amount because the future realization of such loss cannot be reasonably assured and is subject to a full valuation allowance. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2017.

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 Basin is capital intensive. At December 31, 2018, we had approximately $0.4 million in cash and approximately $196.2 million in unused borrowing capacity under the EEH Credit Agreement (discussed below) for a total of approximately $196.5 million in funds available for operational and capital funding. We currently estimate 2019 capital expenditures will be approximately $190 million, which assumes a 16-well program running one rig for our operated acreage in the Midland Basin and a seven-well program for our operated Eagle Ford acreage as well as estimated expenditures for our non-operated Midland Basin properties and land and infrastructure activities. We likely will continue to outspend our cash flows provided by operating activities over at least the next 12 months from the date of this report based on current assumptions. However, we believe we will have sufficient liquidity with cash flows from operations and borrowings under the EEH Credit Agreement for the next 12 months in order to meet our cash requirements. We may consider various financial arrangements or other techniques or transactions, including but not limited to promoted drilling arrangements.

Working Capital, defined as Total current assets less Total current liabilities as set forth in our Consolidated Balance Sheets, was a deficit of $18.3 million as of December 31, 2018 compared to a deficit of $21.8 million as of December 31, 2017. We used $150.0 million to fund our capital program, in addition to $32.6 million to acquire additional oil and natural gas properties, offset by $6.0 in cash proceeds from the disposition of certain non-core oil and natural gas properties in the Eagle Ford Trend, that was facilitated by $102.4 million of net cash provided by our operating activities resulting from increased oil prices as well as increased production resulting from our 2018 drilling and development program, net borrowings of $53.8 million under the EEH Credit Agreement and a reduction of our cash on hand by $22.6 million. Due to the costs incurred related to our drilling program, we may incur additional working capital deficits in the future. We expect that our pace of development, production volumes, 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 acquisition and development activities through available working capital, cash flows from operating activities, borrowings under the EEH Credit Agreement and, various means of corporate and project financing, assuming we can effectively access debt and equity markets. In addition, as indicated above, 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.

Capital Expenditures

We have set our 2019 capital budget, which assumes a one-rig operated program and non-operated activities as currently proposed by operators, for our acreage in the Midland Basin as well as a seven-well program on our operated Eagle Ford acreage. Our anticipated capital expenditures for 2019 are currently estimated at $190 million.

Our accrual basis capital expenditures for the years ended December 31, 2018 and 2017 were as follows:

	Years Ended December 31,	
	2018	**2017**
Drilling and completions	$ 151,059	$ 76,253
Leasehold costs	2,102	3,067
Land	—	1,816
Total capital expenditures	$ 153,161	$ 81,136

In addition to the capital expenditures described above, on October 5, 2018, we closed the Exchange. Under the terms of the Exchange, we acquired 3,899 net operated acres in Reagan County with virtually a 100% working interest, including producing assets representing a net production increase of approximately 350 Boe/d, in exchange for 1,222 net non-operated acres in Glasscock County with an average working interest of 39% and $27.8 million in cash, plus customary closing adjustments.

For further discussion, see *Note 3. Acquisitions and Divestitures* to the Notes to Consolidated Financial Statements included in this report.

Credit Agreement

On November 6, 2018, in connection with a regularly scheduled borrowing base redetermination, the borrowing base under the EEH Credit Agreement was increased from $225.0 million to $275.0 million. As of December 31, 2018, we had $78.8 million of borrowings outstanding, bearing annual interest of 4.479%, resulting in a remaining $196.2 million of borrowing base available under the EEH Credit Agreement.

Impairments to Oil and Natural Gas Properties

During 2018, we recognized $4.6 million of non-cash asset impairments related to certain acreage expirations at our properties located in the Eagle Ford Trend of south Texas. See *Note 7. Oil and Natural Gas Properties* in the Notes to Consolidated Financial Statements for a discussion of how impairments are measured.

Hedging Activities

The following table sets forth our outstanding derivative contracts at December 31, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2019	Crude Oil Swap	3,022,100	$63.09
2019	Crude Oil Basis Swap (1)	365,000	$4.50
2019	Crude Oil Basis Swap (2)	2,675,500	$(5.81)
2019	Natural Gas Swap	3,832,500	$2.86
2019	Natural Gas Basis Swap (3)	3,832,500	$(1.14)
2020	Crude Oil Swap	1,464,000	$65.87
2020	Crude Oil Basis Swap (2)	1,464,000	$(2.74)
2020	Natural Gas Swap	2,562,000	$2.85
2020	Natural Gas Basis Swap (3)	2,562,000	$(1.07)

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

Subsequent to December 31, 2018, we unwound 730 MBbls of Crude Oil Swaps at a weighted average contract price of $54.97/Bbl and 92,000 MMBtu of Natural Gas Swaps at a weighted average contract price of $2.87/MMBtu for 2019. Additionally, we unwound 668 MBbls of WTI Midland Argus Crude Basis Swaps at a weighted average contract price of $(7.19) and 92,000 MMBtu of Natural Gas WAHA Basis Swaps at a weighted average contract price of $(1.07)/MMBtu for 2019. Net proceeds related to the unwound contracts were $2.1 million.

The following table sets forth our outstanding derivative contracts at March 1, 2019. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2019	Crude Oil Swap	2,292,100	$65.67
2019	Crude Oil Basis Swap (1)	365,000	$4.50
2019	Crude Oil Basis Swap (2)	2,007,500	$(5.36)
2019	Natural Gas Swap	3,740,500	$2.86
2019	Natural Gas Basis Swap (3)	3,740,500	$(1.14)
2020	Crude Oil Swap	1,464,000	$65.87
2020	Crude Oil Basis Swap (2)	1,464,000	$(2.74)
2020	Natural Gas Swap	2,562,000	$2.85
2020	Natural Gas Basis Swap (3)	2,562,000	$(1.07)

Obligations and Commitments

We had the following contractual obligations and commitments as of December 31, 2018:

(In thousands)	2019	2020	2021	2022	2023	Thereafter
Debt (1)	$ 318	$ —	$ —	$ 78,828	$ —	$ —
Derivative liabilities	528	1,891	—	—	—	—
Asset retirement obligations	557	106	—	149	234	1,183
Gas contracts (2)	1,643	1,647	680	—	—	—
Office leases	723	—	—	—	—	—
Automobile leases	419	223	77	—	—	—
Total	$ 4,188	$ 3,867	$ 757	$ 78,977	$ 234	$ 1,183

(1) 2019 amount represents interest payable under the EEH Credit Agreement as of December 31, 2018.
(2) We have a non-cancelable fixed cost agreement of $1.6 million per year through May 2021 to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing related to certain Eagle Ford assets in south Texas. As the operator of the properties dedicated to this contract, the gross amount of obligation is provided, however our net share is approximately 31%.

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 natural gas liquids 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, 2018. 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 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 swaps. Swaps are designed so that we receive or make payments based on a differential between fixed and variable prices for crude oil and natural gas. 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.

Income Taxes and Uncertain Tax Positions

We are a U.S. company operating in Texas, as of December 31, 2018, 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 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.

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, 2018 and 2017, the Company has recorded a valuation allowance for its deferred tax assets in the Consolidated Balance Sheets.

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, 2018 or 2017.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil, natural gas and natural gas liquids. 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.

Goodwill

We account for goodwill in accordance with FASB ASC Topic 350, *Intangibles – Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of the liabilities assumed in an acquisition. ASC Topic 350 requires that goodwill be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in an impairment.

We conduct a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our goodwill such as, industry and market conditions, including commodity prices, costs factors, and other company specific events. If we conclude that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then we do not have to perform the two-step impairment test. If after assessing the totality of events or circumstances described, we determine that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If, after performing the two-step goodwill test, it is determined that the carrying value of goodwill is impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired

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, 2018 and 2017, as well as an adjustment to Net loss in the Consolidated Statement of Operations for the years ended December 31, 2018 and 2017.

As of December 31, 2018, Earthstone and Lynden US held 44.7% of the outstanding membership interests in EEH while Bold Holdings, the noncontrolling party, held the remaining 55.3%. See further discussion in *Note 9. 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 a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and therefore are not required to provide the information required under this item.

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

As previously disclosed in our Current Report on Form 8-K, filed with the SEC on March 30, 2018, effective March 29, 2018, we dismissed Grant Thornton LLP (“Grant Thornton”) as our independent registered public accounting firm and (ii) appointed Moss Adams LLP (“Moss Adams”), effective immediately upon the completion of Moss Adams’ client acceptance procedures, which occurred on March 30, 2018, to serve as our new independent registered public accounting firm to audit our financial statements as of and for the fiscal year ending December 31, 2018. In connection with this change in our independent registered public accounting firm, there was no disagreement, as defined in Item 304(a)(1)(iv) of Regulation S-K, or a reportable event, as defined in Item 304(a)(1)(v) of Regulation S-K.

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, 2018. 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, 2018.

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, 2018, 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, 2018 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, 20*18, 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, 20*18, 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 sheet of Earthstone Energy, Inc. *and subsidiaries* as of *December 31, 20*18, the related *consolidated* statements of operations, *equity and cash flows* for the year then ended, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 12, 2019 expressed an unqualified opinion on those *consolidated* financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management 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 12, 2019

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

See list of "Executive Officers of the Company" 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 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

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 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

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

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

PART IV

Item 15. Exhibits, Financial Statements Schedules

Exhibit No.	Description	Incorporated by Reference: Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
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		
2.2(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		
2.3	Contribution Agreement dated October 17, 2018 by and among Sabalo Holdings, LLC, Earthstone Energy Holdings, LLC and Earthstone Energy, Inc.	8-K	001-35049	2.1	October 17, 2018		
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		
3.2	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 Common Stock Certificate of Earthstone Energy, Inc.	10-K	001-35049	4.2	June 16, 2011		
4.2	Specimen Class A Common Stock Certificate of Earthstone Energy, Inc.	8-K	001-35049	4.1	May 15, 2017		
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†	Earthstone Energy, Inc. 2011 Equity Incentive Compensation Plan.	Def. Proxy Statement	001-35049	Appendix A	July 29, 2011		
10.4†	Form of Restricted Stock Unit Agreement (Executive Management)	8-K	001-35049	10.1	June 2, 2016		
10.5†	Form of Restricted Stock Unit Agreement (Employee)	8-K	001-35049	10.2	June 2, 2016		
10.6†	Form of Restricted Stock Unit Agreement (Non-Employee Director)	8-K	001-35049	10.3	June 2, 2016		

10.70	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
10.8	Credit Agreement dated May 9, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association as Syndication Agent and the Lenders party thereto.	8-K	001-35049	10.2	May 15, 2017
10.8(a)	First Amendment to Credit Agreement dated October 11, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, and Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, and the Lenders party thereto.	10-K	001-35049	10.2	March 15, 2018
10.8(b)	Second Amendment to Credit Agreement dated December 1, 2017, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, and Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, and the Lenders party thereto.	8-K	001-35049	10.1	December 4, 2017
10.8(c)	Third Amendment to Credit Agreement dated May 23, 2018, by and among Earthstone Energy Holdings, LLC, as Borrower, Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, and Bold Operating, LLC, as guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, and the Lenders party thereto.	8-K	001-35049	10.1	May 23, 2018
10.9	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
10.10	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
10.11	Purchase and Sale Agreement dated November 16, 2017, by and between Earthstone Legacy Properties, LLC and Statoil Oil & Gas LP.	10-K	001-35049	10.2	March 15, 2018
10.12†	Performance Unit Award Agreement (Executive Management).	8-K	001-35049	10.2	March 2, 2018

10.13†	Amended and Restated 2014 Long Term Incentive Plan dated June 6, 2018	8-K	001-35049	10.1	June 6, 2018		
10.14	Termination Agreement dated December 21, 2018 by and among Earthstone Energy, Inc., Earthstone Energy Holdings, LLC and Sabalo Holdings, LLc.	8-K	001-35049	10.1	December 24, 2018		
10.15†	Form of Performance Unit Agreement (Executive Management).	8-K	001-35049	10.2	February 1, 2019		
14.0	Code of Business Conduct and Ethics.	10-KSB/A	001-35049	14.1	May 11, 2005		
21.1	List of Subsidiaries.					X	
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X	
23.2	Consent of Grant Thornton LLP.					X	
23.3	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	

† 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/ Frank A. Lodzinski
		Name:	Frank A. Lodzinski
Date:	March 12, 2019	Title:	*Chief Executive Officer*
			(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/ Frank A. Lodzinski Frank A. Lodzinski	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)	March 12, 2019
/s/ Tony Oviedo Tony Oviedo	Executive Vice President, Accounting and Administration (Principal Financial Officer and Principal Accounting Officer)	March 12, 2019
/s/ Jay F. Joliat Jay F. Joliat	Director	March 12, 2019
/s/ Phil D. Kramer Phil D. Kramer	Director	March 12, 2019
/s/ Ray Singleton Ray Singleton	Director	March 12, 2019
/s/ Wynne M. Snoots, Jr. Wynne M. Snoots, Jr.	Director	March 12, 2019
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	March 12, 2019
/s/ Brad A. Thielemann Brad A. Thielemann	Director	March 12, 2019
/s/ Zachary G. Urban Zachary G. Urban	Director	March 12, 2019
/s/ Robert L. Zorich Robert L. Zorich	Director	March 12, 2019

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 sheet of Earthstone Energy, Inc. *and subsidiaries* (the "Company") as of *December 31, 20*18, the related *consolidated* statements of operations, equity and cashflows for the year then ended, 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, 2018, and the consolidated results of its operations and its cash flows for the year then ended, 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, 20*18, 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 12, 2019 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 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 the *consolidated* financial statements are free of material misstatement, whether due to error or fraud. Our audit 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 audit 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 audit provides a reasonable basis for our opinion.

/s/ Moss Adams, LLP

Houston, Texas
March 12, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Earthstone Energy Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheet of Earthstone Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, the related consolidated statements of operations, equity, and cash flows for the year ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for the year ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

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

Houston, Texas
March 15, 2018

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

ASSETS	December 31, 2018	December 31, 2017
Current assets:		
Cash	$ 376	$ 22,955
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	13,683	14,978
Joint interest billings and other, net of allowance of $134 and $138 at December 31, 2018 and 2017, respectively	4,166	7,778
Derivative asset	43,888	184
Prepaid expenses and other current assets	1,443	1,178
Total current assets	63,556	47,073
Oil and gas properties, successful efforts method:		
Proved properties	755,443	605,039
Unproved properties	266,140	275,025
Land	5,382	5,534
Total oil and gas properties	1,026,965	885,598
Accumulated depreciation, depletion and amortization	(127,256)	(118,028)
Net oil and gas properties	899,709	767,570
Other noncurrent assets:		
Goodwill	17,620	17,620
Office and other equipment, net of accumulated depreciation of $2,490 and $2,093 at December 31, 2018 and 2017, respectively	662	947
Derivative asset	21,121	—
Other noncurrent assets	1,640	1,207
TOTAL ASSETS	$ 1,004,308	$ 834,417
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 26,452	$ 33,472
Revenues and royalties payable	28,748	10,288
Accrued expenses	22,406	8,707
Asset retirement obligation	557	—
Derivative liability	528	11,805
Advances	3,174	4,587
Total current liabilities	81,865	68,859
Noncurrent liabilities:		
Long-term debt	78,828	25,000
Asset retirement obligation	1,672	2,354
Derivative liability	1,891	1,826
Deferred tax liability	13,489	10,515
Other noncurrent liabilities	71	131
Total noncurrent liabilities	95,951	39,826
Commitments and Contingencies (Note 16)		
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; 28,696,321 and 27,584,638 issued and outstanding at December 31, 2018 and 2017, respectively	29	28
Class B Common Stock, $0.001 par value, 50,000,000 shares authorized; 35,452,178 and 36,052,169 issued and outstanding at December 31, 2018 and 2017, respectively	35	36
Additional paid-in capital	517,073	503,932
Accumulated deficit	(182,497)	(224,822)
Total Earthstone Energy, Inc. equity	334,640	279,174
Noncontrolling interest	491,852	446,558
Total equity	826,492	725,732
TOTAL LIABILITIES AND EQUITY	$ 1,004,308	$ 834,417

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,	
	2018	**2017**
REVENUES		
Oil	$ 140,775	$ 88,536
Natural gas	7,396	8,777
Natural gas liquids	17,185	10,765
Total revenues	165,356	108,078
OPERATING COSTS AND EXPENSES		
Lease operating expense	20,522	19,658
Severance taxes	8,060	6,060
Impairment expense	4,581	72,191
Depreciation, depletion and amortization	47,568	36,915
General and administrative expense	28,159	27,067
Transaction costs	13,524	4,732
Accretion of asset retirement obligation	169	434
Exploration expense	630	1
Total operating costs and expenses	123,213	167,058
Gain on sale of oil and gas properties, net	1,919	9,105
Income (loss) from operations	**44,062**	**(49,875)**
OTHER INCOME (EXPENSE)		
Interest expense, net	(2,898)	(2,699)
Write-off of deferred financing costs	—	(526)
Gain (loss) on derivative contracts, net	60,947	(7,986)
Litigation settlement	(4,675)	—
Other income (expense), net	247	(20)
Total other income (expense)	53,621	(11,231)
Income (loss) before income taxes	97,683	(61,106)
Income tax (expense) benefit	(2,470)	16,373
Net income (loss)	95,213	(44,733)
Less: Net income (loss) attributable to noncontrolling interest	52,888	(32,219)
Net income (loss) attributable to Earthstone Energy, Inc.	$ 42,325	$ (12,514)
Net income (loss) per common share attributable to Earthstone Energy, Inc.:		
Basic	$ 1.50	$ (0.53)
Diluted	$ 1.50	$ (0.53)
Weighted average common shares outstanding:		
Basic	28,153,885	23,589,973
Diluted	28,217,774	23,589,973

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											
	Common Stock	Class A Common Stock	Class B Common Stock	Common Stock	Class A Common Stock	Class B Common Stock	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Earthstone Energy, Inc. Stockholders' Equity	Noncontrolling Interest	Total Equity
At January 1, 2017	22,289,177	—	—	$ 23	$ —	$ —	$ 454,202	$ (212,308)	$ (460)	$ 241,457	$ —	$ 241,457
Stock-based compensation expense	—	—	—	—	—	—	6,601	—	—	6,601	—	6,601
Vesting of restricted stock units prior to completion of Bold Contribution Agreement	382,804	—	—	—	—	—	(1)	—	—	(1)		(1)
Common stock exchanged in connection with Bold Contribution Agreement	(22,656,624)	22,656,624	—	(23)	23	—	—	—	—	—	—	—
Treasury shares converted to Class A Common Stock	(15,357)	15,357	—	—	—	—	—	—	—	—	—	—
Closing of Bold Contribution Agreement	—	150,000	—	—	—	—	12,872	—		12,872	479,007	491,879
Class B Common Stock sold in connection with Bold Contribution Agreement	—	—	36,070,828	—	—	36	—	—	—	36	—	36
Deferred tax consequences of Bold Contribution Agreement	—	—	—	—	—	—	(8,270)	—	—	(8,270)	—	(8,270)
Vesting of restricted stock units following completion of Bold Contribution Agreement	—	259,355	—	—	—	—	—	—	—	—	—	—
Class A Common Stock retained by the Company in exchange for payment of recipient mandatory tax withholdings	—	61,055	—	—	—	—	(675)	—	—	(675)	—	(675)
Cancellation of treasury shares	—	(76,412)	—	—	—	—	(460)	—	460	—	—	—
Class A Common Stock issued, net of offering costs of $2.2 million	—	4,500,000	—	—	5	—	39,433	—	—	39,438	—	39,438
Class B Common Stock converted to Class A Common Stock	—	18,659	(18,659)	—	—	—	230	—	—	230	(230)	—
Net loss	—	—	—	—	—	—	—	(12,514)	—	(12,514)	(32,219)	(44,733)
At December 31, 2017	—	27,584,638	36,052,169	$ —	$ 28	$ 36	$ 503,932	$ (224,822)	$ —	$ 279,174	$ 446,558	$ 725,732
Stock-based compensation expense	—	—	—	—	—	—	7,071	—	—	7,071	—	7,071
Vesting of restricted stock units, net of taxes paid	—	511,692	—	—	—	—	—	—	—	—	—	—
Class A Common Stock retained by the Company in exchange for payment of recipient mandatory tax withholdings	—	169,893	—	—	—	—	(1,524)	—	—	(1,524)	—	(1,524)
Cancellation of treasury shares	—	(169,893)	—	—	—	—	—	—	—	—	—	—
Class B Common Stock converted to Class A Common Stock	—	599,991	(599,991)	—	1	(1)	7,594	—	—	7,594	(7,594)	—
Net income	—	—	—	—	—	—	—	42,325	—	42,325	52,888	95,213

At December 31, 2018	—	28,696,321	35,452,178	$ —	$ 29	$ 35	$ 517,073	$ (182,497)	$ —	$ 334,640	$ 491,852	$ 826,492

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,	
	2018	**2017**
Cash flows from operating activities:		
Net income (loss)	$ 95,213	$ (44,733)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment of proved and unproved oil and gas properties	4,581	72,191
Depreciation, depletion and amortization	47,568	36,915
Accretion of asset retirement obligations	169	434
Gain on sale of oil and gas properties, net	(1,919)	(9,105)
Settlement of asset retirement obligations	(79)	(9)
Total (gain) loss on derivative contracts, net	(60,947)	7,986
Operating portion of net cash paid in settlement of derivative contracts	(15,090)	(708)
Stock-based compensation	7,071	6,601
Deferred income taxes	2,470	(16,388)
Write-off of deferred financing costs	—	526
Amortization of deferred financing costs	325	257
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(8,195)	444
(Increase) decrease in prepaid expenses and other current assets	(376)	(335)
Increase (decrease) in accounts payable and accrued expenses	1,132	(282)
Increase (decrease) in revenues and royalties payable	31,869	(2,888)
Increase (decrease) in advances	(1,413)	45
Net cash provided by operating activities	102,379	50,951
Cash flows from investing activities:		
Acquisition of oil and gas properties	(32,551)	(55,609)
Additions to oil and gas properties	(149,999)	(65,262)
Additions to office and other equipment	(170)	(167)
Proceeds from sale of oil and gas properties	5,965	34,735
Net cash used in investing activities	(176,755)	(86,303)
Cash flows from financing activities:		
Proceeds from borrowings	156,830	85,000
Repayments of borrowings	(103,002)	(74,298)
Cash paid related to the exchange and cancelation of Common Stock	(1,524)	(675)
Deferred financing costs	(507)	(1,358)
Issuance of Class A Common Stock, net of offering costs of $2.2 million	—	39,438
Net cash provided by financing activities	51,797	48,107
Net increase (decrease) in cash and cash equivalents	(22,579)	12,755
Cash at beginning of period	22,955	10,200
Cash at end of period	$ 376	$ 22,955
Supplemental disclosure of cash flow information		
Cash paid for:		
Interest	$ 2,290	$ 2,495
Non-cash investing and financing activities:		
Class B Common Stock issued in Bold Contribution Agreement	$ —	$ 489,842
Class A Common Stock issued in Bold Contribution Agreement	$ —	$ 2,037
Accrued capital expenditures	$ 22,801	$ 19,883
Asset retirement obligations	$ 252	$ (42)

The accompanying notes are an integral part of these 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.

Certain prior period amounts have been reclassified to conform to current period presentation within the Consolidated Financial Statements. Prior period Re-engineering and workovers in the Consolidated Statements of Operations have been reclassified from its own line item and included in Lease operating expenses, within Operating Costs and Expenses, to conform to current period presentation. Additionally, prior-period Stock-based compensation in the Consolidated Statements of Operations has been reclassified from its own line item and included in General and administrative expense, within Operating Costs and Expenses, to conform to current-period presentation. These reclassifications had no effect on Income (loss) from operations or any other subtotal in the Consolidated Statements of Operations.

Bold Contribution Agreement

On May 9, 2017, Earthstone completed a 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, a Texas limited liability company ("Lynden Op"), Bold Energy Holdings, LLC, a Texas limited liability company ("Bold Holdings"), and Bold Energy III LLC, a Texas limited liability company ("Bold"). The purpose of the Bold Contribution Agreement was to provide for, among other things described below, the business combination between Earthstone and Bold, which owned significant developed and undeveloped oil and natural gas properties in the Midland Basin of Texas (the "Bold Transaction").

The Bold Transaction was structured in a manner commonly known as an "Up-C." Under this structure and the Bold Contribution Agreement, (i) Earthstone recapitalized its common stock into two classes – Class A common stock, $0.001 par value per share (the "Class A Common Stock"), and Class B common stock, $0.001 par value per share (the "Class B Common Stock"), and all of Earthstone's existing outstanding common stock, $0.001 par value per share (the "Common Stock"), was recapitalized on a one-for-one basis for Class A Common Stock (the "Recapitalization"); (ii) Earthstone transferred all of its membership interests in Earthstone Operating, LLC, Sabine River Energy, LLC, EF Non-Op, LLC and Earthstone Legacy Properties, LLC (formerly Earthstone GP, LLC) and $36,071 in cash from the sale of Class B Common Stock to Bold Holdings (collectively, the "Earthstone Assets") to EEH, in exchange for 16,791,296 membership units of EEH (the "EEH Units"); (iii) Lynden US transferred all of its membership interests in Lynden Op to EEH in exchange for 5,865,328 EEH Units; (iv) Bold Holdings transferred all of its membership interests in Bold to EEH in exchange for 36,070,828 EEH Units and purchased 36,070,828 shares of Class B Common Stock issued by Earthstone for $36,071; and (v) Earthstone granted an aggregate of 150,000 fully vested shares of Class A Common Stock under Earthstone's 2014 Long-Term Incentive Plan, as amended (the "2014 Plan"), to certain employees of Bold. Each EEH Unit, together with one share of Class B Common Stock, are convertible into one share of Class A Common Stock.

The Bold Transaction was recorded in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, Business Combinations, and is consolidated in these financial statements 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, including changes to additional paid-in capital to reflect the noncontrolling interest within equity in the Consolidated Balance Sheet as of December 31, 2018 at the noncontrolling interest's respective membership interest in EEH.

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 our estimates. All reserve data included in these Consolidated Financial Statements 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, and valuation of derivative instruments. 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 19. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited).*

Accounts Receivable

Accounts receivable include 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.

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 $0.1 million and $0.1 million at December 31, 2018 and 2017, respectively.

Derivative Instruments

The Company utilizes derivative instruments in order to manage exposure to commodity price risk associated with future oil and natural gas production. 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 Gain (loss) 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 Gain (loss) 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. There were no impairments to Goodwill recorded in the years ended December 31, 2018 and 2017, respectfully. For further discussion, see *Note 8. Goodwill*.

Noncontrolling Interest

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, 2018 and 2017, as well as an adjustment to Net income in the Consolidated Statement of Operations for the years ended December 31, 2018 and 2017. As of December 31, 2018, Earthstone and Lynden US owned a 44.7% membership interest in EEH while Bold Holdings, the noncontrolling third party, owned the remaining 55.3%. See further discussion in *Note 9. 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 our organization and management, we have 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 14. Asset Retirement Obligations*.

Business Combinations

The Company accounts for its acquisitions of oil and gas properties not commonly controlled in accordance with FASB 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

Revenues for the sale of oil, natural gas and natural gas liquids are recognized when the recognition criteria of ASC 606 “Revenue from Contracts with Customers,” are met, which generally occurs as the product is delivered to customers’ custody transfer points and collectability is reasonably assured. The Company fulfills its performance obligations under its customer contracts through daily 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. 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 owners 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. The Company follows the sales method of accounting for gas imbalances. The Company had no significant gas imbalances as of December 31, 2018 or 2017.

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 2018, three purchasers accounted for 27%, 11% and 10%, respectively, of the Company's oil, natural gas, and natural gas liquids revenues. In 2017, three purchasers accounted for 18%, 14% and 14%, 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 2018 and 2017. Additionally, at December 31, 2018, five purchasers accounted for 22%, 17%, 13%, 11% and 11%, respectively, of the Company's oil, natural gas and natural gas liquids receivables. At December 31, 2017, three purchasers accounted for 20%, 13% and 12%, 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, 2018 and 2017.

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 2018, no operator distributed 10% or more of the Company's oil, natural gas and natural gas liquids revenues. In 2017, one operator distributed 10% of the Company's oil, natural gas and natural gas liquids revenues. No other operator accounted for 10% or more of the Company's oil, natural gas, and natural gas liquids revenues during 2017.

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, 2018, the Company had a net derivative asset position of $62.6 million. At December 31, 2017, the Company had no 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 Company's common stock on the grant date and recognized over the vesting period using the straight-line method. Stock-based compensation expense related to performance-based restricted stock units, which cliff vest, is 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. See *Note 12. Stock-Based Compensation* for further details.

Income Taxes

The Company is a U.S. company operating primarily in Texas, as of December 31, 2018, as well as 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.

Following the closing of the Bold Transaction, the Company continues to record 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. Following the Bold Transaction, 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, 2018 and 2017, 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, 2018 or 2017.

On December 22, 2017, the United States enacted tax reform legislation commonly known as the Tax Cuts and Jobs Act (the “TCJA”), resulting in significant modifications to existing law. Our consolidated financial statements for the year ended December 31, 2017, reflect certain effects of the TCJA, which includes the federal corporate income tax rate reduction to 21%. Consistent with SEC Staff Accounting Bulletin ("SAB") No. 118, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA in 2017. In accordance with SEC guidance, provisional amounts may be refined as a result of additional guidance from, and interpretations by, U.S. regulatory and standard-setting bodies, and changes in assumptions. In the subsequent period, provisional amounts will be adjusted for the effects, if any, of interpretative guidance issued after December 31, 2017, by the U.S. Department of the Treasury. As of December 31, 2018, we have finalized the accounting for the enactment of the TCJA.

Recently Issued Accounting Standards

Revenue Recognition – On January 1, 2018, the Company adopted the FASB Accounting Standards Update (“ASU”) for “Revenue from Contracts with Customers,” which superseded the revenue recognition requirements in “Topic 605, Revenue Recognition,” using the modified retrospective method. Adoption of this standard did not have a significant impact on the consolidated statements of operations or cash flows. Additionally, the Company implemented processes to ensure new contracts are reviewed for the appropriate accounting treatment and generate the disclosures required under the new standard.

Statement of Cash Flows – In August 2016, the FASB issued updated guidance that clarifies how certain cash receipts and cash payments are presented in the statement of cash flows. This update provides guidance on eight specific cash flow issues. The standards update is effective for interim and annual periods beginning after December 15, 2017 and should be applied retrospectively to all periods presented. Early adoption is permitted. The Company adopted the new standard, as required, beginning with the first quarter of 2018, with no material impact on its Consolidated Financial Statements.

Business Combinations – In January 2017, the FASB issued updated guidance that clarifies the definition of a business, which amends the guidance used in evaluating whether a set of acquired assets and activities represents a business. The guidance requires an entity to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities is not considered a business. As a result, acquisition fees and expenses will be capitalized to the cost basis of the property acquired, and the tangible and intangible components acquired will be recorded based on their relative fair values as of the acquisition date. The standard is effective for all public business entities for annual periods beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted for periods for which financial statements have not yet been issued. The Company adopted the new standard, as required, beginning with the first quarter of 2018, with no material impact on its Consolidated Financial Statements.

Compensation – Stock Compensation – In May 2017, the FASB issued updated guidance that provides clarity about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The update is effective for annual periods beginning after December 15, 2017, and early adoption is permitted, including adoption in any interim period. The Company adopted the new standard, as required, beginning with the first quarter of 2018, with no material impact on its Consolidated Financial Statements.

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

ASU 2016-02 requires lessees to recognize lease assets and liabilities (with terms in excess of 12 months) on the balance sheet and disclose key quantitative and qualitative information about leasing arrangements. The Company has substantially completed its current process of assessing existing contracts, as well as future potential contracts, to determine the impact of its application on its consolidated financial statements and related disclosures. The evaluation process includes review of contracts for drilling rigs, office facilities, compression services, field vehicles and equipment, general corporate leased equipment, and other existing arrangements to support its operations that may contain a lease component. The Company's evaluation process will not include review of its mineral leases as they are outside the scope of ASC Topic 842.

The Company plans to elect the package of practical expedients within ASU 2016-02 that allows an entity to not reassess, prior to the effective date, (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases or (iii) initial direct costs for any existing leases, but does not plan to elect the hindsight practical expedient when determining the lease term of existing contracts at the effective date. The new standard also provides practical expedients for an entity's ongoing accounting. The Company currently expects to elect the short-term lease recognition exemption for all leases that qualify. The Company also currently expects to elect the practical expedient to not separate lease and non-lease components for the majority of classes of underlying assets.

Additionally, the Company also plans to elect the practical expedient under ASU 2018-01 and not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. The Company is working to complete its evaluation of the impact of ASC Topic 842 on its financial statements, accounting policies and internal controls, including implementation of processes to capture, classify and account for leases within the scope of the new guidance and to provide the related disclosures.

The Company will adopt this guidance as of January 1, 2019, the transition date, using the simplified transition method described in ASU 2018-11, in which a cumulative-effect adjustment will be recognized in the opening balance of retained earnings in the period of adoption. At this time, the impact upon adoption of ASC Topic 842 is expected to result in recognition of an immaterial amount of additional operating liabilities, with corresponding right-of-use assets, on the Company's Consolidated Balance Sheet for leases existing as of January 1, 2019, based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases. The adoption of this standard is not expected to have a material impact on the Company's Consolidated Statement of Income nor Consolidated Statement of Cash Flows.

Intangibles – Goodwill and Other – In January 2017, the FASB issued updated guidance simplifying the test for goodwill impairment. The update eliminates Step 2 of the goodwill impairment test. Instead, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The update is effective for annual and interim periods beginning after December 15, 2019 and early adoption is permitted for interim or annual goodwill impairment tests performed after January 1, 2017. The Company is in the process of evaluating the impact of this guidance, if any, on its Consolidated Financial Statements.

Compensation – Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting – In June 2018, the FASB issued updated guidance simplifying the guidance on nonemployee share-based payments. The update is effective for annual and interim periods beginning after December 15, 2018 and early adoption is permitted. The Company adopted the new standard, as required, beginning with the first quarter of 2018, with no material impact on its Consolidated Financial Statements.

Codification Improvements – In July 2018, the FASB issued an update which does not prescribe any new accounting guidance, but instead makes minor improvements and clarifications of several different FASB Accounting Standards Codification areas based on comments and suggestions made by various stakeholders. Certain updates are applicable immediately while others provide for a transition period to adopt as part of the next fiscal year beginning after December 15, 2018. The Company adopted the new standard, as required, beginning with the first quarter of 2018, with no material impact on its Consolidated Financial Statements.

Fair Value Measurements – In August 2018, the FASB issued an update which modifies the disclosure requirements on fair value measurements in Topic 820. The ASU is effective for fiscal years beginning after December 15, 2019 and early adoption is permitted. The Company is in the process of evaluating the impact of this update, if any, on its Consolidated Financial Statements.

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.

Exchange Involving Monetary Consideration

On October 5, 2018, the Company closed a transaction in the Midland Basin that included producing properties and undeveloped acreage (the "Exchange"). GAAP required the assets received by the Company to be treated as a business combination, under ASC 805, and the assets conveyed to the other party to be treated as a disposition of assets (discussed in *Divestitures* below).

An allocation of the purchase price was prepared using, among other things, a reserve report prepared by qualified reserve engineers and priced as of the acquisition date. The market assumptions as to the future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of the future development and operating costs, projections of future rates of production, expected recovery rate and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs; see Note 5. Fair Value Measurements, below.

As a result, the Company, in exchange for cash of $25.9 million and value for the assets conveyed of $37.1 million, the Company recorded $65.8 million in Oil and gas properties, as well as $2.8 million in accounts payable related known purchase price adjustments, in its Consolidated Balance Sheet as of December 31, 2018. The effective date of the Exchange was September 1, 2018

Bold Transaction

On May 9, 2017, Earthstone completed the Bold Transaction described in *Note 1. Organization and Basis of Presentation*.

An allocation of the purchase price was prepared using, among other things, a reserve report prepared by qualified reserve engineers and priced as of the acquisition date.

The following table summarizes the consideration transferred, fair value of assets acquired and liabilities assumed (*in thousands, except share and share price amounts*):

Consideration:		
Shares of Class A Common Stock issued pursuant to the Bold Contribution Agreement to certain employees of Bold		150,000
EEH Units issued to Bold Holdings		36,070,828
Total equity interest issued in the Bold Transaction		36,220,828
Closing per share price of Class A Common Stock as of May 9, 2017	$	13.58
Total consideration transferred (1) (2)	$	491,879
Fair value of assets acquired:		
Cash and cash equivalents	$	2,355
Other current assets		10,078
Oil and gas properties (3)		557,704
Amount attributable to assets acquired	$	570,137
Fair value of liabilities assumed:		
Long-term debt (4)	$	58,000
Current liabilities		17,042
Deferred tax liability		2,857
Noncurrent asset retirement obligations		359
Amount attributable to liabilities assumed	$	78,258

(1) Consideration included 150,000 shares of Class A Common Stock recorded above based upon its fair value which was determined using the closing price of $13.58 per share on May 9, 2017.

(2) Consideration was 36,070,828 EEH Units. Additionally, Bold Holdings purchased 36,070,828 shares of Class B Common Stock for $36,071. Each EEH Unit, together with one share of Class B Common Stock, is convertible into one share of Class A Common Stock. The fair value of the consideration was determined using the closing price of the Company’s Class A Common Stock of $13.58 per share on May 9, 2017.

(3) The market assumptions as to the future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of the future development and operating costs, projections of future rates of production, expected recovery rate and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs; see *Note 5. Fair Value Measurements*, below.

(4) Concurrent with the closing of the Bold Transaction, EEH repaid Bold’s outstanding borrowings of $58.0 million under its credit agreement.

The following unaudited supplemental pro forma condensed results of operations present consolidated information as though the Bold Transaction and the Bakken Sale (discussed below) had been completed as of January 1, 2017. The unaudited supplemental pro forma financial information was derived from the historical consolidated and combined statements of operations for Bold and Earthstone and adjusted to include: (i) depletion expense applied to the adjusted basis of the properties acquired and (ii) to eliminate non-recurring transaction costs directly related to the Bold Transaction that do not have a continuing impact on the Company's operating results. 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 combined company for the periods presented or that may be achieved by the combined 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*):

	Year Ended December 31, 2017	
	(Unaudited)	
Revenue	$	126,839
Loss before taxes	$	(44,461)
Net loss	$	(35,617)
Less: Net loss attributable to noncontrolling interest	$	(22,005)
Net loss attributable to Earthstone Energy, Inc.	$	(13,612)
Pro forma net loss per common share attributable to Earthstone Energy, Inc.:		
Basic and diluted	$	(0.57)

The Company has included in its Consolidated Statements of Operations, revenues of $50.2 million and direct operating expenses of $23.8 million for the period from May 9, 2017 to December 31, 2017 related to the properties acquired in the Bold Transaction.

Divestitures

During the year ended December 31, 2018, the Company sold certain non-core properties for total cash consideration of approximately $6.0 million, while eliminating approximately $0.8 million of future abandonment obligations. The sales resulted in net gains of approximately $4.7 million recorded in Gain on sale of oil and gas properties, net in the Consolidated Statements of Operations.

In association with the Exchange, the Company received value of $37.1 million for Net oil and gas properties conveyed of $39.9 million and recognized a $2.8 million loss on sale of oil and gas properties recorded in Gain on sale of oil and gas properties, net for the year ended December 31, 2018.

On December 20, 2017, the Company sold all of its oil and natural gas leases, oil and natural gas wells and associated assets located in the Williston Basin in North Dakota (the "Bakken Sale") for a net cash consideration of approximately $26.4 million after normal and customary purchase price adjustments of $0.9 million to account for net cash flows from the effective date to the closing date. The sale resulted in a net gain of approximately $3.0 million recorded in Gain on sale of oil and gas properties, net in the Consolidated Statements of Operations. The effective date of the sale was December 1, 2017.

For the year ended December 31, 2017, the Company sold certain non-core properties for a total cash consideration of approximately $7.5 million, while eliminating approximately $4.0 million of future abandonment obligations. The sales resulted in a net gain of approximately $6.1 million recorded in Gain on sale of oil and gas properties in the Consolidated Statements of Operations.

Note 4. Transaction Costs

On October 17, 2018, Earthstone, EEH and Sabalo Holdings, LLC ("Sabalo Holdings") entered into a contribution agreement (the "Contribution Agreement") which provided for the contribution by Sabalo Holdings of all its interests in Sabalo Energy, LLC ("Sabalo Energy") and Sabalo Energy, Inc. to EEH (the "Sabalo Acquisition"). On December 21, 2018, Earthstone, EEH and Sabalo Holdings entered into a termination agreement (the "Termination Agreement"), pursuant to which the parties mutually agreed to terminate the Contribution Agreement.

In connection with the Termination Agreement, Earthstone, EEH and Sabalo Holdings also agreed to release each other from certain claims and liabilities arising out of or related to the Contribution Agreement and the transactions contemplated therein or thereby. All other related agreements were also terminated in conjunction with the termination of the Contribution Agreement.

During the year ended December 31, 2018, the Company recorded transaction costs totaling approximately $13.5 million of which $13.4 million was associated with the terminated Sabalo Acquisition, including payment to Sabalo Holdings of $1.6 million for reimbursement of expenses.

During the year ended December 31, 2017, the Company recorded $4.7 million in transaction costs primarily associated with the Bold Transaction completed in May 2017. See *Note 3. Acquisitions and Divestitures*.

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, 2018.

Fair Value on a Recurring Basis

Derivative financial instruments are carried at fair value and measured on a recurring basis. The derivative financial instruments consist of swaps for crude oil and natural gas. The Company's swaps are valued based on a discounted future cash flow model. The primary input for the model is published forward commodity price curves. The swaps are also designated as Level 2 within the valuation hierarchy.

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

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, 2018	Level 1	Level 2	Level 3	Total
Financial assets				
Derivative asset- current	$ —	$ 43,888	$ —	$ 43,888
Derivative asset- noncurrent	—	21,121	—	21,121
Total financial assets	$ —	$ 65,009	$ —	$ 65,009
Financial liabilities				
Derivative liability - current	$ —	$ 528	$ —	$ 528
Derivative liability - noncurrent	—	1,891	—	1,891
Total financial liabilities	$ —	$ 2,419	$ —	$ 2,419
December 31, 2017				
Financial assets				
Derivative asset- current	$ —	$ 184	$ —	$ 184
Total financial assets	$ —	$ 184	$ —	$ 184
Financial liabilities				
Derivative liability - current	$ —	$ 11,805	$ —	$ 11,805
Derivative liability - noncurrent	—	1,826	—	1,826
Total financial liabilities	$ —	$ 13,631	$ —	$ 13,631

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 and goodwill. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances.

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. 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 dictate that the fair value of goodwill may be less than its carrying amount. Such test includes an assessment of qualitative and quantitative factors. See *Note 8. Goodwill*.

Business Combinations

The Company records the identifiable assets acquired and liabilities assumed at fair value at the date of acquisition on a nonrecurring basis. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and natural gas production, commodity prices based on NYMEX commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. The future oil and natural gas pricing used in the valuation is a Level 2 assumption. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the determination of fair value of the acquisition include the Company's estimate operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. The Company’s acquisitions are discussed in *Note 3. Acquisitions and Divestitures*.

Asset Retirement Obligations

The asset retirement obligation estimates are derived from historical costs and management’s expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. The significant inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, well life, inflation and credit-adjusted risk-free rate. See *Note 14. Asset Retirement Obligations* for a reconciliation of the beginning and ending balances of the liability for the Company’s asset retirement obligations.

Note 6. Derivative Financial 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 and basis swaps agreements. Swaps exchange floating price risk in the future for a fixed price at the time of the hedge. 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, 2020. 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, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

Period	Commodity	Volume (Bbls / MMBtu)	Price ($/Bbl / $/MMBtu)
2019	Crude Oil Swap	3,022,100	$63.09
2019	Crude Oil Basis Swap (1)	365,000	$4.50
2019	Crude Oil Basis Swap (2)	2,675,500	$(5.81)
2019	Natural Gas Swap	3,832,500	$2.86
2019	Natural Gas Basis Swap (3)	3,832,500	$(1.14)
2020	Crude Oil Swap	1,464,000	$65.87
2020	Crude Oil Basis Swap (2)	1,464,000	$(2.74)
2020	Natural Gas Swap	2,562,000	$2.85
2020	Natural Gas Basis Swap (3)	2,562,000	$(1.07)

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

Subsequent to December 31, 2018, the Company unwound 730 MBbls of Crude Oil Swaps at a weighted average contract price of $54.97/Bbl and 92,000 MMBtu of Natural Gas Swaps at a weighted average contract price of $2.87/MMBtu for 2019. Additionally, the Company unwound 668 MBbls of WTI Midland Argus Crude Basis Swaps at a weighted average contract price of $(7.19) and 92,000 MMBtu of Natural Gas WAHA Basis Swaps at a weighted average contract price of $(1.07)/MMBtu for 2019. Net proceeds related to the unwound contracts were $2.1 million.

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, 2018			December 31, 2017		
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	$ 48,662	$ (4,774)	$ 43,888	$ 184	$ —	$ 184
Commodity contracts	Derivative liability - current	$ 5,302	$ (4,774)	$ 528	$ 11,805	$ —	$ 11,805
Commodity contracts	Derivative asset - noncurrent	$ 23,605	$ (2,484)	$ 21,121	$ —	$ —	$ —
Commodity contracts	Derivative liability - noncurrent	$ 4,375	$ (2,484)	$ 1,891	$ 1,826	$ —	$ 1,826

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**	**2018**	**2017**
Unrealized gain (loss)	Not presented	Not presented	$ 76,037	$ (7,278)
Realized gain (loss)	Operating portion of net cash paid in settlement of derivative contracts	Not presented	(15,090)	(708)
	Total (gain) loss on derivative contracts, net	Gain (loss) on derivative contracts, net	$ 60,947	$ (7,986)

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 (loss) 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 $47.1 million and $36.4 million for the years ended December 31, 2018 and 2017, 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, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

The Company had the following non-cash asset impairment charges to its oil and natural gas properties for the years ended December 31, 2018 and 2017 (*in thousands*):

	Years Ended December 31,	
	2018	2017
Proved property	$ —	$ 63,131
Unproved property	4,581	9,060
Total	$ 4,581	$ 72,191

Accumulated impairments to proved and unproved oil and natural gas properties as of December 31, 2018 and 2017 were $121.1 million and $148.2 million, respectively.

Note 8. 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 dictate that the carrying value of goodwill may not be recoverable. Such test includes an assessment of qualitative and quantitative factors.

The Company did not have any non-cash impairment charges to its goodwill for the years ended December 31, 2018 or 2017.

Accumulated impairments to Goodwill as of December 31, 2018 and 2017 were $19.1 million.

Note 9. Noncontrolling Interest

As a result of the Bold Transaction, Earthstone became the sole managing member of, and has a controlling interest in, EEH. As the sole managing member of EEH, Earthstone operates and controls all of the business and affairs of EEH and its subsidiaries. Immediately following the Bold Transaction, Earthstone and Lynden US owned a 38.6% membership interest in EEH while Bold Holdings owned the remaining 61.4%.

The Bold Transaction was recorded in accordance with FASB ASC Topic 805, Business Combinations, and is consolidated in these financial statements 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, including changes to Additional paid-in capital to reflect the noncontrolling interest within equity in the Consolidated Balance Sheet as of December 31, 2017 at the noncontrolling interest's respective membership interest in EEH. A reconciliation of the equity attributable to the noncontrolling interest as of May 9, 2017 is as follows (*in thousands*):

Total considerations transferred (1)	$ 491,879
Change to additional paid-in capital to reflect the noncontrolling interest within equity at their membership interest	(12,872)
Portion of equity attributable to noncontrolling interest (2)	$ 479,007

(1) See *Note 3. Acquisitions and Divestitures*.
(2) Represents 61.4% of total equity attributable to EEH as of May 9, 2017.

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 loss attributable to noncontrolling interest in the Consolidated Statements of Operations for the year ended December 31, 2018 represents the portion of net income or loss 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, 2018 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, 2018:

	EEH Units Held By Earthstone and Lynden US	%	EEH Units Held By Others	%	Total EEH Units Outstanding
As of December 31, 2017	27,584,638	43.3%	36,052,169	56.7%	63,636,807
EEH Units issued in connection with the vesting of restricted stock units and issuance of Class A Common Stock	511,692		—		511,692
EEH Units and Class B Common Stock converted to Class A Common Stock	599,991		(599,991)		—
As of December 31, 2018	28,696,321	44.7%	35,452,178	55.3%	64,148,499

The following table summarizes the activity for the equity attributable to the noncontrolling interest for the year ended December 31, 2018 (*in thousands*):

	2018
As of December 31, 2017	$ 446,558
EEH Units and Class B Common Stock converted to Class A Common Stock	(7,594)
Net income attributable to noncontrolling interest	52,888
As of December 31, 2018	$ 491,852

Note 10. 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 (Common Stock through May 8, 2017 and Class A Common Stock from May 9, 2017 through December 31, 2018). 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)	2018	2017
Net income (loss) attributable to Earthstone Energy, Inc.	$ 42,325	$ (12,514)
Net income (loss) per common share attributable to Earthstone Energy, Inc.:		
Basic	$ 1.50	$ (0.53)
Diluted	$ 1.50	$ (0.53)
Weighted average common shares outstanding		
Basic	28,153,885	23,589,973
Add potentially dilutive securities:		
Unvested restricted stock units	63,889	—
Diluted weighted average common shares outstanding	28,217,774	23,589,973

Class B Common Stock has been excluded, as its conversion would eliminate noncontrolling interest and Net income attributable to noncontrolling interest of $52.9 million would be added back to Net income (loss) attributable to Earthstone Energy, Inc., having no dilutive effect on Net income (loss) per common share attributable to Earthstone Energy, Inc. For the year ended December 31, 2017, the Company excluded 105,422 shares for the dilutive effect of restricted stock units in calculating diluted earnings per share as the effect was anti-dilutive due to the net loss incurred these periods.

Note 11. Common Stock

On May 9, 2017, and in connection with the completion of the Bold Transaction, Earthstone recapitalized its Common Stock into two classes, as described in *Note 1. Organization and Basis of Presentation*, Class A Common Stock and Class B Common Stock. At that time, all of Earthstone's existing outstanding Common Stock was automatically converted on a one-for-one basis into Class A Common Stock.

Class A Common Stock

At December 31, 2018 and 2017, there were 28,696,321 and 27,584,638 shares of Class A Common Stock issued and outstanding, respectively. During the years ended December 31, 2018 and 2017, as a result of the vesting and settlement of restricted stock units under the 2014 Plan, Earthstone issued 681,585 and 703,214 shares of Class A Common Stock, respectively, of which 169,893 and 61,055 shares of Class A Common Stock, respectively, were retained as treasury stock and canceled to satisfy the related employee income tax liability. On July 1, 2017, Earthstone retired and returned the 15,357 shares of treasury stock to authorized but unissued shares of Class A Common Stock. Additionally, on May 9, 2017, under the Bold Contribution Agreement, Earthstone issued 150,000 shares of Class A Common Stock valued at approximately $2.0 million on that date. For additional information, see *Note 3. Acquisitions and Divestitures*.

Class A Common Stock Offering

In October 2017, Earthstone completed a public offering of 4,500,000 shares of Class A Common Stock, at an issue price of $9.25 per share. Earthstone received net proceeds from this offering of $39.4 million, after deducting underwriters' fees and offering expenses of $2.2 million. The net proceeds from the offering were used to repay outstanding indebtedness under the EEH Credit Agreement, as described in *Note 13. Long-Term Debt*.

Class B Common Stock

At December 31, 2018 and 2017, there were 35,452,178 and 36,052,169 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, 2018 and 2017, 599,991 and 18,659 shares, respectively, of Class B Common Stock and EEH Units were exchanged for an equal number of shares of Class A Common Stock. On May 9, 2017, in connection with Earthstone's completion of the Bold Transaction, Earthstone issued 36,070,828 shares of Class B Common Stock in exchange for $36 thousand. For additional information, see *Note 3. Acquisitions and Divestitures*.

Note 12. Stock-Based Compensation

Restricted Stock Units

The 2014 Plan allows, among other things, for the grant of restricted stock units ("RSUs"). On June 6, 2018, at the annual meeting of stockholders, Earthstone's stockholders approved an amendment and restatement of the 2014 Plan, including increasing the shares of Class A Common Stock that may be issued under the Plan by 600,000 shares, to a total of 6.4 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. Prior to May 9, 2017, the Company determined the fair value of granted RSUs based on the market price of the Common Stock on the date of the grant. Beginning on May 9, 2017, the Company began determining 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 Sheet.

The table below summarizes unvested RSU activity for the year ended December 31, 2018:

	Shares	Weighted-Average Grant Date Fair Value
Unvested RSUs at December 31, 2017	969,245	$ 9.89
Granted	567,500	$ 8.41
Forfeited	(44,165)	$ 10.87
Vested	(681,585)	$ 9.86
Unvested RSUs at December 31, 2018	810,995	$ 8.83

During the year ended December 31, 2018, Earthstone granted 561,000 RSUs to employees and 6,500 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 2018 and 2017 were $4.8 million and $9.3 million, respectively, with a weighted average grant date fair value per share of $8.41 and $9.80, respectively. The total vesting date fair value of the RSUs that vested during 2018 and 2017 was $6.2 million and $8.3 million, respectively. As of December 31, 2018, there was approximately $6.6 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 0.99 years.

For the years ended December 31, 2018 and 2017, stock-based compensation related to RSUs was $6.1 million and $6.6 million, respectively.

Performance Units

On February 28, 2018, the Board granted 252,500 performance units ("PSUs") to certain named 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 28, 2018 and ending on February 28, 2021 (the "Performance Period") 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 Total Shareholder Return ("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 Performance Period. Accordingly, the potential aggregate number of shares of Class A Common Stock issuable under the outstanding PSU awards range from zero to 505,000.

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 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 Performance Period plus cash dividends paid over the 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 Performance Period.

As of December 31, 2018, there were 252,500 PSUs outstanding. There were no PSUs outstanding as of December 31, 2017. The unrecognized compensation expense related to the PSU awards at December 31, 2018 was $2.5 million which will be amortized over the remaining vesting period. The weighted average remaining vesting period of the unrecognized compensation expense is 1.12 years.

The Company is accounting for this award as a market-based award which was valued utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes for an award and establishes fair value based on the most likely outcome. Under the Monte Carlo Simulation pricing model, assuming a risk-free rate of 2.4% and volatilities ranging from 41.7% to 199.8%, the Company calculated the weighted average grant date fair value per PSU to be $13.75. For the year ended December 31, 2018, Stock-based compensation related to the PSUs was approximately $1.0 million. There was no Stock-based compensation related to the PSUs for the year ended December 31, 2017.

Note 13. Long-Term Debt

Credit Agreement

On November 6, 2018, in connection with a regularly scheduled borrowing base redetermination, the borrowing base under the EEH Credit Agreement was increased from $225.0 million to $275.0 million.

On May 23, 2018, Earthstone Energy Holdings, LLC ("EEH" or the "Borrower"), a subsidiary of Earthstone, each of Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden USA Operating, LLC, Bold Energy III LLC, Bold Operating, LLC, as guarantors (the "Guarantors"), BOKF, NA dba Bank Of Texas, as Administrative Agent, and the lenders party thereto (the "Lenders"), entered into an amendment (the "Amendment") to the Credit Agreement dated May 9, 2017, by and among EEH, as Borrower, the Guarantors, BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association, as Syndication Agent, and the Lenders (together with all amendments or other modifications, the "EEH Credit Agreement"). Among other things, the Amendment increased the borrowing base from $185.0 million to $225.0 million, provided for a 50-basis point decrease in the interest rate on outstanding loans, increased flexibility related to hedging limitations and provided the ability to obtain short-term borrowings via a swingline as a part of the borrowing base.

On May 9, 2017, in connection with the closing of the Bold Transaction, the Company exited its credit agreement dated December 19, 2014, by and among Earthstone, OVR Operating, LLC, EF Non-OP, LLC, Sabine River Energy, LLC, Basic Petroleum Services, Inc., BOKF, NA dba Bank of Texas, and the lenders party thereto (as amended, modified or restated from time to time, the "ESTE Credit Agreement"). At that time, all outstanding borrowings of $10.0 million under the ESTE Credit Agreement were repaid and

$0.5 million of remaining unamortized deferred financing costs were expensed and included in Write-off of deferred financing costs in the Consolidated Statements of Operations.

On May 9, 2017, EEH (the "Borrower"), Earthstone Operating, LLC, EF Non-Op, LLC, Sabine River Energy, LLC, Earthstone Legacy Properties, LLC, Lynden Op, Bold, Bold Operating, LLC (the "Guarantors"), BOKF, NA dba Bank Of Texas, as Agent and Lead Arranger, Wells Fargo Bank, National Association as Syndication Agent and the lenders party thereto (the "Lenders"), entered into a credit agreement (the "EEH Credit Agreement").

The borrowing base under the EEH Credit Agreement is subject to redetermination on or about November 1st and May 1st of each year. The amounts borrowed under the EEH Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus 1.75% to 2.75% or (b) the prime lending rate of Bank of Texas plus 0.75% to 1.75%, depending on the amounts borrowed under the EEH Credit Agreement. Principal amounts outstanding under the EEH Credit Agreement are due and payable in full at maturity on May 9, 2022. All of the obligations under the EEH Credit Agreement, and the guarantees of those obligations, are secured by substantially all of EEH's assets. Additional payments due under the EEH Credit Agreement include paying a commitment fee of 0.375% or 0.50%, depending on borrowing base utilization, per year to the Lenders in respect of the unutilized commitments thereunder, as well as certain other customary fees.

The EEH 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, enter into sale and leaseback transactions, pay dividends and make 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 EEH Credit Agreement requires EEH to maintain the following financial covenants: a current ratio, as defined, of not less than 1.0 to 1.0 and a leverage ratio of not greater than 4.0 to 1.0. 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 (excluding any debt from obligations relating to non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives) to (ii) the product of EBITDAX for such fiscal quarter multiplied by four. The term "EBITDAX" means, for any period, the sum of consolidated net income for such period plus (a) the following expenses or charges to the extent deducted from consolidated net income in such period: (i) interest, (ii) taxes, (iii) depreciation, (iv) depletion, (v) amortization, (vi) non-cash losses under FASB ASC 815 as a result of changes in the fair market value of derivatives, (vii) exploration expenses, (viii) impairment expenses, and (ix) non-cash compensation expenses and minus (b) to the extent included in consolidated net income in such period, non-cash gains under FASB ASC 815 as a result of changes in the fair market value of derivatives.

The EEH 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 if Frank A. Lodzinski ceases to serve and function as Chief Executive Officer of EEH and the majority of the Lenders do not approve of Mr. Lodzinski's successor. 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, 2018, EEH was in compliance with the covenants under the EEH Credit Agreement.

As of December 31, 2018, the Company had a $275.0 million borrowing base under the EEH Credit Agreement, of which $78.8 million was outstanding, bearing annual interest of 4.479%, resulting in an additional $196.2 million of borrowing base availability under the EEH Credit Agreement. At December 31, 2017, there were $25.0 million of borrowings outstanding under the EEH Credit Agreement.

For the year ended December 31, 2018, the Company had borrowings of $156.8 million and $103.0 million in repayments of borrowings.

For the years ended December 31, 2018 and 2017, interest on all outstanding debt averaged 4.16% and 4.26% per annum, respectively, of which excluded commitment fees of $0.8 million and $0.3 million for each period ended, respectively, and amortization of deferred financing costs of $0.3 million for each period ended, respectively.

The Company capitalized $0.5 million and $1.4 million, respectively, of costs associated with the credit agreements for the years ended December 31, 2018 and 2017. 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.

Note 14. 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, 2018 and 2017 *(in thousands)*:

	2018	2017
Beginning asset retirement obligations	$ 2,354	$ 6,013
Liabilities acquired (1)	298	359
Liabilities incurred	102	77
Property dispositions (1)	(766)	(4,401)
Liabilities settled	(79)	(9)
Accretion expense	169	434
Revision of estimates	151	(119)
Ending asset retirement obligations	$ 2,229	$ 2,354

(1) See *Note 3. Acquisitions and Divestitures* for additional information on the Company's acquisition and property disposition activities.

Note 15. 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.

Flatonia Energy, LLC ("Flatonia"), which owns approximately 10.3% of the outstanding Class A Common Stock as of December 31, 2018, is a party to a joint operating agreement (the "Operating Agreement") with the Company. The Operating Agreement covers certain jointly owned oil and natural gas properties located in the Eagle Ford Trend of south Texas. In connection with the Operating Agreement, the Company made payments to Flatonia of $12.4 million and $26.5 million, and received payments from Flatonia of $6.1 million and $5.4 million, respectively, for the years ended December 31, 2018 and 2017. At December 31, 2018 and 2017, amounts receivable due from Flatonia in connection with the Operating Agreement were $0.8 million and $1.3 million, respectively. Payables related to revenues outstanding and due to Flatonia as of December 31, 2018 and 2017 were $1.6 million and $2.1 million, respectively.

Our majority shareholder consists of various investment funds managed by a venture capital firm who may manage other investments in entities with which we interact in the normal course of business.

Note 16. Commitments and Contingencies

Contractual Commitments

Future minimum contractual commitments as of December 31, 2018 under non-cancelable agreements having initial or remaining terms in excess of one year are as follows:

	2019	2020	2021	2022	2023	Thereafter
Gas contract	$ 1,643	$ 1,647	$ 680	$ —	$ —	$ —
Office leases	723	—	—	—	—	—
Automobile leases	419	223	77	—	—	—
Total	$ 2,785	$ 1,870	$ 757	$ —	$ —	$ —

The Company has a non-cancelable fixed cost agreement of $1.6 million per year through May 2021 to reserve pipeline capacity of 10,000 MMBtu per day for gathering and processing related to certain Eagle Ford assets in south Texas. As the operator of the properties dedicated to this contract, the gross amount of obligation is provided, however the Company's net share is approximately 31%.

Additionally, the Company leases corporate office space in The Woodlands, Texas and Midland, Texas. Rent expense was approximately $0.9 million and $0.9 million, for the years ended December 31, 2018 and 2017, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2018 are shown 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. Lodzinksi et al.: On June 2, 2017, Nicholas Olenik filed a purported shareholder class and derivative action in the Delaware Court of Chancery against Earthstone's Chief Executive Officer, along with other members of the Board, EnCap, Bold, Bold Holdings and OVR. The complaint alleges that Earthstone's directors breached their fiduciary duties in connection with the Bold Contribution Agreement. The Plaintiff asserts that the directors negotiated the Bold Transaction to benefit EnCap and its affiliates, failed to obtain adequate consideration for the Earthstone shareholders 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. The suit seeks unspecified damages and purports to assert claims derivatively on behalf of Earthstone and as a class action on behalf of all persons who held Common Stock up to March 13, 2017, excluding defendants and their affiliates. 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 February 6, 2019, the Delaware Supreme Court heard oral arguments from the Plaintiff and Defendants' counsel and has not yet issued an opinion. Earthstone and each of the other defendants believe the claims are entirely without merit and they intend to mount a vigorous defense. The ultimate outcome of this suit is uncertain, and while Earthstone is confident in its position, any potential monetary recovery or loss to Earthstone cannot be estimated at this time.

On August 18, 2017, litigation captioned Trinity Royalty Partners, LP v. Bold Energy III LLC, et al. was filed with the 142nd Judicial District of the District Court in Midland County, Texas, asserting breach of contract and indemnity claims for alleged damages from loss of property relating to two oil and natural gas wells in which Bold was the operator. Trinity Royalty Partners, LP ("Trinity") claimed that Bold was required to indemnify Trinity under the terms of an assignment and a Participation and Joint Development Agreement between Bold and Trinity. Damages were claimed to include costs incurred in attempting to repair and restore an oil and natural gas well and for the loss of future reserves attributable to both wells. On November 16, 2018 Trinity and Bold entered into a Confidential Settlement Agreement and Mutual Release whereby Trinity and Bold agreed to settle the lawsuit and release all claims and counterclaims asserted by the parties. As a result, a $4.7 million expense has been recorded to Litigation settlement in the Consolidated Statements of Operations for the year ended December 31, 2018.

Note 17. Income Taxes

On December 22, 2017, President Trump signed into law the Tax Cuts and Jobs Act ("TCJA") that significantly changes the federal income taxation of business entities. The TCJA, among other things, reduces the corporate income tax rate to 21%, partially limits the deductibility of business interest expense and net operating losses, imposes a one-time tax on unrepatriated earnings from certain foreign subsidiaries, taxes offshore earnings at reduced rates regardless of whether they are repatriated and allows the immediate deduction of certain capital expenditures instead of deductions for depreciation expense over time. Consistent with Staff Accounting Bulletin No. 118 issued by the SEC, which provides for a measurement period of one year from the enactment date to finalize the accounting for effects of the TCJA, the Company provisionally recorded income tax expense of $7.8 million related to the TCJA in the fourth quarter of 2017. As of December 31, 2018, the Company has finalized the accounting for the enactment of the TCJA.

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, 2018 and 2017 (*in thousands*):

	Years Ended December 31, 2018	Years Ended December 31, 2017
Current:		
Federal	$ —	$ —
State	—	(15)
Total current	—	(15)
Deferred:		
Federal	(1,398)	16,186
State	(1,072)	202
Total deferred	(2,470)	16,388
Total income tax (expense) benefit	$ (2,470)	$ 16,373

Effective Tax Rate

A reconciliation of the effective tax rate to the statutory rate for the years ended December 31, 2018 and 2017 is as follows (*in thousands, except percentages*):

	Years Ended December 31,					
	2018			2017		
	U.S.	Canada	Total	U.S.	Canada	Total
Net income (loss) before income taxes	$ 97,683	$ —	$ 97,683	$ (61,082)	$ (24)	$ (61,106)
Statutory rate	21%	27%		34%	26%	
Tax expense (benefit) computed at statutory rate	20,513	—	20,513	(20,768)	(8)	(20,776)
Noncontrolling interest	(11,475)	—	(11,475)	12,118	—	12,118
Non-deductible general and administrative expenses	94	—	94	168	—	168
Return to accrual	—	—	—	(486)	—	(486)
Refundable tax credits	(505)	—	(505)	—	—	—
State income taxes, net of Federal benefit	1,208	—	1,208	(191)	—	(191)
Valuation allowance	(7,393)	—	(7,393)	(15,483)	6	(15,477)
Federal rate change	—	—	—	7,824	—	7,824
State rate change	28	—	28	445	—	445
Rate differential on Canadian activity	—	—	—	—	2	2
Total income tax expense (benefit)	$ 2,470	$ —	$ 2,470	$ (16,373)	$ —	$ (16,373)
Effective tax rate	2.5%	—%	2.5%	26.8%	—%	26.8%

During the year ended December 31, 2018, the Company recorded total income tax expense of $2.5 million which included (1) deferred income tax expense for Lynden US of $1.9 million as a result of its share of the distributable income from EEH, offset by a $0.5 million discrete income tax benefit related to refundable AMT tax credits resulting from the TCJA, (2) deferred income tax expense for Earthstone of $7.4 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 $1.1 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, 2018.

During the year ended December 31, 2017, the Company recorded a total income tax benefit of $16.4 million which included (1) income tax benefit of $8.6 million, of which $4.8 million related to the reduction of that amount in its deferred tax liability resulting from the federal corporate income tax rate reduction to 21%, (2) a $7.7 million income tax benefit for Earthstone as a discrete item during the current reporting period, which resulted from a change in assessment of the realization of its net deferred tax assets due to the deferred tax liability that was recorded with respect to its investment in EEH as part of the Bold Transaction as an adjustment to Additional paid-in capital in the Consolidated Statement of Equity, and (3) income tax expense of $12.6 million related to the reduction of the amount in its deferred tax asset resulting from the federal corporate income tax rate reduction to

21% which was fully offset by the reduction in its valuation allowance for that amount because the future realization of such loss cannot be reasonably assured and is subject to a full valuation allowance. Lynden Corp incurred no material income or loss, or related income tax expense or benefit, for the year ended December 31, 2017.

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, 2018 and 2017 are as follows (*in thousands*):

	December 31,	
	2018	2017
Deferred noncurrent income tax assets (liabilities):		
Oil & gas properties	$ 11,164	$ 2,998
Basis difference in subsidiary obligation	(2,211)	(2,268)
Investment in Partnerships	(18,517)	(111)
Federal net operating loss carryforward	12,940	12,986
Net deferred noncurrent tax assets	3,376	13,605
Valuation allowance	(16,865)	(24,120)
Net deferred tax liability	$ (13,489)	$ (10,515)

As of December 31, 2018, the Company had a valuation allowance recorded against its deferred tax assets of $16.9 million which is in excess of its net deferred noncurrent tax assets of $3.4 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, 2018, 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 $13.1 million deferred tax asset, a $9.6 million deferred tax liability, a $3.8 million deferred tax asset and a $3.9 million deferred tax liability, respectively, before considering the valuation allowance of $16.9 million.

As of December 31, 2017, the Company had a valuation allowance recorded against its deferred tax assets of $24.1 million which is in excess of its Net deferred noncurrent tax assets of $13.6 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, 2017, 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 $20.5 million deferred tax asset, a $7.7 million deferred tax liability, a $3.6 million deferred tax asset and a $2.8 million deferred tax liability, respectively, before considering the valuation allowance of $24.1 million.

As of December 31, 2018, the Company had estimated U.S. net operating loss carryforwards of $42.4 million, the first expiring in 2034 and the last in 2038, and estimated Canadian net operating loss carryforwards of $10.0 million, the first expiring in 2024 and the last in 2037. 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 $28.0 million limited by Sec 382 resulting from the Lynden Arrangement. The Company continues to evaluate the impact, if any, of potential Sec 382 limitations.

The Company's tax returns are subject to periodic audits by the various jurisdictions in which the Company operates. These audits can result in adjustments of taxes due or adjustments of the NOL carryforwards that are available to offset future taxable income. Generally, the Company’s income tax years 2011 through 2018 remain open and subject to examination by the Internal Revenue Service or state tax jurisdictions where it conducts operations. In certain jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination.

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, 2018, 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, 2018, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

Note 18. Profit Sharing 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, 2018 and 2017 were $0.5 million and $0.3 million, respectively.

Note 19. 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 2018 and 2017 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,	
	2018	2017
Acquisition cost (1):		
Proved	$ 41,569	$ 315,376
Unproved	31,268	245,589
Exploration costs:		
Exploratory drilling	—	—
Geological and geophysical	630	1
Development costs	153,161	77,876
Total additions	$ 226,628	$ 638,842

(1) Acquisition costs incurred during 2018 consisted primarily of an acreage trade in the Midland Basin and during 2017 consisted primarily of the assets acquired in the Bold Transaction, both described in *Note 3. Acquisitions and Divestitures* of the Notes to Consolidated Financial Statements.

During the years ended December 31, 2018 and 2017, additions to oil and natural gas properties of $0.3 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, 2018 and 2017, the Company had no capitalized exploratory well costs, nor 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, 2018 and 2017, are summarized below (*in thousands*):

		December 31,	
	2018		2017
Oil and gas properties, successful efforts method:			
Proved properties	$ 830,843	$	708,646
Accumulated impairment to proved properties	(75,400)		(103,608)
Proved properties, net of accumulated impairments	755,443		605,038
Unproved properties	311,828		319,569
Accumulated impairment to Unproved properties	(45,688)		(44,543)
Unproved properties, net of accumulated impairments	266,140		275,026
Land	5,382		5,534
Total oil and gas properties, net of accumulated impairments	1,026,965		885,598
Accumulated depreciation, depletion and amortization	(127,256)		(118,028)
Net oil and gas properties	$ 899,709	$	767,570

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, 2018 and 2017 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 judgement. 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, 2018 and 2017 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 $65.56 per barrel and $51.34 per barrel, respectively. The natural gas prices as of December 31, 2018 and 2017 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $3.10 per MMBtu and $2.98 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, 2018 and 2017 averaged $28.81 per barrel and $22.59 per barrel, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. 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 NGLs reserves for the years ended December 31, 2018 and 2017 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Balance - December 31, 2016	7,111	20,401	1,540	12,051
Extensions and discoveries	19,558	29,644	6,264	30,763
Sales of minerals in place	(1,833)	(6,853)	(1)	(2,976)
Purchases of minerals in place	28,176	46,709	9,950	45,911
Production	(1,828)	(3,260)	(500)	(2,872)
Revision to previous estimates	(3,857)	4,447	215	(2,901)
Balance - December 31, 2017	47,327	91,088	17,468	79,976
Extensions and discoveries	10,148	17,673	3,116	16,209
Sales of minerals in place	(2,651)	(14,300)	(1,562)	(6,596)
Purchases of minerals in place	3,532	9,890	1,629	6,810
Production	(2,370)	(3,610)	(655)	(3,627)
Revision to previous estimates	3,048	12,476	947	6,075
Balance - December 31, 2018	59,034	113,217	20,943	98,847
Proved developed reserves:				
December 31, 2016	6,052	13,545	1,051	9,361
December 31, 2017	11,949	23,336	4,123	19,961
December 31, 2018	14,325	26,110	4,969	23,646
Proved undeveloped reserves:				
December 31, 2016	1,059	6,856	489	2,690
December 31, 2017	35,378	67,752	13,345	60,015
December 31, 2018	44,709	87,107	15,974	75,201

The table below presents the quantities of proved oil, natural gas and NGLs reserves attributable to noncontrolling interests as of December 31, 2018 and 2017:

As of December 31, 2018	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Proved developed	7,917	14,430	2,746	13,068
Proved undeveloped	24,709	48,140	8,828	41,560
Total proved	32,626	62,570	11,574	54,628

As of December 31, 2017	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Proved developed	6,775	13,232	2,338	11,318
Proved undeveloped	20,059	38,415	7,566	34,028
Total proved	26,834	51,647	9,904	45,346

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* In 2018, total extensions and discoveries of 16.2 MMBOE was a result of successful drilling results and well performance primarily related to the Midland Basin.
- *Sales of minerals in place.* Sales of minerals in place totaled 6.6 MMBOE during 2018, which consisted of 4.7 MMBOE resulting from the disposition of non-operated properties in the Midland Basin as part of an acreage trade and 1.9 MMBOE related to the disposition of non-operated Eagle Ford properties, both further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2018, total purchases of minerals in place of 6.8 MMBOE were primarily attributable to developed non-producing wells and undeveloped acreage acquired in the Midland Basin as part of an acreage trade, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

- *Revision to previous estimates.* In 2018, the upward revisions of prior reserves of 6.1 MMBOE consisted of improved PUD reserves of 5.8 MMBOE with improved proved developed reserves of 0.3 MMBOE. PUD revisions are a result of our successful drilling efforts in the Midland Basin as well as improved commodity prices.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 30,763 MBOE was a result of successful drilling results and well performance primarily related to the Midland Basin. The closing of the Bold Transaction in May 2017 which included primarily operated acreage in the Midland Basin was a significant contributor to this.
- *Sales of minerals in place.* Sales of minerals in place totaled 2,976 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Purchases of minerals in place.* In 2017, total purchases of minerals in place of 45,911 MBOE were primarily attributable to the Bold Transaction, whereby the Company acquired interests in 63 producing oil and natural gas wells, developed non-producing wells and undeveloped acreage in the Midland Basin, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.
- *Revision to previous estimates.* In 2017, the downward revisions of prior reserves of 2,901 MBOE consisted of negative revisions to PUD reserves of 4,832 MBOE with improved proved developed reserves of 1,931 MBOE. PUD revisions are a result of (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. Positive revisions are primarily a result of increased oil and natural gas prices during 2017.

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, 2018 and 2017 were as follows (*in MBOE*):

Proved undeveloped reserves at December 31, 2016	2,690
Conversions to developed	(2,756)
Extensions and discoveries	27,977
Sales of minerals in place	(391)
Purchases of minerals in place	37,327
Revision to previous estimates	(4,832)
Proved undeveloped reserves at December 31, 2017 (1)	60,015
Conversions to developed	(4,419)
Extensions and discoveries	13,734
Sales of minerals in place	(4,702)
Purchases of minerals in place	4,735
Revision to previous estimates	5,838
Proved undeveloped reserves at December 31, 2018 (2)	75,201

(1) Includes 34,029 MBOE attributable to noncontrolling interests.

(2) Includes 41,560 MBOE attributable to noncontrolling interests.

2018 Changes in Proved Undeveloped Reserves

Conversions to developed. In the Company's year-end 2017 plan to develop its PUDs within five years, the Company estimated that $51.9 million of capital would be expended in 2018 and that it would convert 4.3 MMBOE, which was consistent with the $55.4 million actually spent to convert 4.4 MMBOE to developed.

Extensions and discoveries. Additionally, 13.7 MMBOE were added as extensions and discoveries due to successful drilling results on the Company's acreage positions because of the wells it drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to the Company's acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 4.7 MMBOE during 2018, which consisted of 3.7 MMBOE resulting from the disposition of non-operated properties in the Midland Basin as part of an acreage trade and 1.0 MMBOE related to the disposition of non-operated Eagle Ford properties, both further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Purchases of minerals in place. In 2018, purchases of minerals in place of 4.7 MMBOE were attributable to developed non-producing wells and undeveloped acreage acquired in the Midland Basin as part of an acreage trade, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements.

Revision to previous estimates. Revisions of 5.8 MMBOE were primarily due to our successful drilling efforts in the Midland Basin as well as improved commodity prices.

2017 Changes in Proved Undeveloped Reserves

Conversions to developed. In the Company's year-end 2016 plan to develop its PUDs within five years, the Company estimated that $6.9 million of capital would be expended in 2017 and that it would convert 732 MBOE. Because of the improvement in commodity prices and the change in its development plan for 2017, the Company actually spent $8.5 million to convert 622 MBOE to developed. The Company's plan changed in that it developed more oil PUDs and elected not to participate in natural gas PUDs which included the above mentioned 443 MBOE associated with the Eagle Ford non-participation. The capital to develop the Company's oil PUDs was higher on a per unit basis than the natural gas PUDs however the margins are higher for oil PUDs. The oil PUDs further benefited the Company's longer-term operated development plans. Since the Bold Transaction closed in May 2017, the associated capital plan for the properties acquired in the Bold Transaction during 2017 was not considered in the Company's year-end 2016 report. The Company did however incur $63.4 million to convert 2,134 MBOE of purchased PUD reserves to Developed.

Extensions and discoveries. Additionally, 27,977 MBOE were added as extensions and discoveries due to successful drilling results on the Company's acreage positions because of the wells it drilled. The increase was also supported by successful drilling results by other operators directly offsetting and in close proximity to the Company's acreage. All of these drilling results increased the confidence of the reservoir continuity and performance of the associated reservoirs which increased the number of PUDs primarily in the Midland Basin.

Sales of minerals in place. Sales of minerals in place totaled 391 MBOE during 2017 and were primarily related to the disposition of the Bakken properties, as further described in *Note 3. Acquisitions and Divestitures* in the Notes to Consolidated Financial Statements

Purchases of minerals in place. During 2017, 37,327 MBOE were added to PUD reserves upon the closing of the Bold Transaction.

Revision to previous estimates. Revisions of 4,832 MBOE were primarily due to (1) removal of approximately 2,011 MBOE of reserves due to delayed development plans of other operators in the Midland Basin that management previously expected to be developed within five years, (2) reduction of 2,378 MBOE upon the closing of the Bold Transaction and making adjustments to development plans and PUD reserve assignments, and (3) non-participation in three Eagle Ford natural gas PUDs that were expected to develop 443 MBOE. This non-participation has no impact on the Company's ability to participate in future wells in this acreage position.

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, 2018 and 2017, 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 is as follows (*in thousands*):

	December 31,	
	2018	**2017**
Future cash inflows	$ 4,479,757	$ 2,948,989
Future production costs	(1,013,131)	(757,716)
Future development costs	(963,536)	(677,093)
Future income tax expense	(90,570)	(33,644)
Future net cash flows	2,412,520	1,480,536
10% annual discount for estimated timing of cash flows	(1,453,068)	(887,836)
Standardized measure of discounted future net cash flows (1)	$ 959,452	$ 592,700

(1) At December 31, 2018 and 2017, the portion of the standardized measure of discounted future net cash flows attributable to noncontrolling interests was $530.2 million and $336.1 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, 2018 (*in thousands*):

	December 31,	
	2018	**2017**
Beginning of year	$ 592,700	$ 85,883
Sales of oil and gas produced, net of production costs	(136,143)	(81,926)
Sales of minerals in place	(41,320)	(15,553)
Net changes in prices and production costs	319,486	155,629
Extensions, discoveries, and improved recoveries	185,540	201,801
Changes in income taxes, net	(43,108)	(5,941)
Previously estimated development costs incurred during the period	153,161	76,447
Net changes in future development costs	(316,765)	(168,940)
Purchases of minerals in place	57,013	244,785
Revisions of previous quantity estimates	144,356	68,705
Accretion of discount	51,222	28,985
Changes in timing of estimated cash flows and other	(6,690)	2,825
End of year (1)	$ 959,452	$ 592,700

(1) At December 31, 2018 and 2017, the portion of the standardized measure of discounted future net cash flows attributable to noncontrolling interests was $530.2 million and $336.1 million, respectively.

Exhibit 21.1

SUBSIDIARIES OF THE COMPANY

	Jurisdiction of Organization
Earthstone Operating, LLC	Texas
Earthstone Legacy Properties, LLC	Texas
Earthstone Energy Holdings, LLC	Delaware
EF Non-Op, LLC	Texas
Sabine River Energy, LLC	Texas
Lynden Energy Corp.	British Columbia, Canada
Lynden USA Inc.	Utah
Lynden USA Operating, LLC	Texas
Bold Energy III, LLC.	Texas
Bold Operating, LLC	Texas

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100	306 WEST SEVENTH STREET, SUITE 302	1000 LOUISIANA STREET, SUITE 1900
AUSTIN, TEXAS 78729-1707	FORT WORTH, TEXAS 76102-4987	HOUSTON, TEXAS 77002-5008
512-249-7000	817- 336-2461	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, 2018, 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 February 11, 2019 into the Registration Statements on Form S-3 (File Nos. 333-205466, 333-213543, 333-218277 and 333-224334) and Form S-8 (File Nos. 333-210734, 333-221248 and 333-227720) 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 12, 2019

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 15, 2018, with respect to the consolidated financial statements included in the Annual Report of Earthstone Energy, Inc. on Form 10-K for the year ended December 31, 2017. We consent to the incorporation by reference of said reports in the Registration Statements of Earthstone Energy, Inc. on Form S-3 (File No. 333-224334, 333-213543, 333-205466, and 333-218277) and on Form S-8 (File No. 333-227720, 333-210734, and 333-221248).

/s/ GRANT THORNTON LLP

Houston, Texas
March 12, 2019

Exhibit 23.3

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-205466, 333-213543, 333-218277 and 333-224334) and Form S-8 (Nos. 333-210734, 333-221248 and 333-227720) of Earthstone Energy, Inc. (the "Company") of our reports dated March 12, 2019, 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 for the year ended December 31, 2018.

/s/ Moss Adams, LLP

Houston, Texas
March 12, 2019

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Frank A. Lodzinski, 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 12, 2019

/s/ Frank A. Lodzinski
Frank A. Lodzinski
Chief Executive Officer

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 12, 2019

/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, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Lodzinski, 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 12, 2019

/s/ Frank A. Lodzinski
Frank A. Lodzinski
Chief Executive Officer

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, 2018, 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 12, 2019

/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

13640 BRIARWICK DRIVE, SUITE 100 306 WEST SEVENTH STREET, SUITE 302 1000 LOUISIANA STREET, SUITE 1900
AUSTIN, TEXAS 78729-1106 FORT WORTH, TEXAS 76102-4987 HOUSTON, TEXAS 77002-5008
512-249-7000 817- 336-2461 713-651-9944

www.cgaus.com

February 11, 2019

Robert Anderson
President
Earthstone Energy, Inc.
1400 Woodloch Forest Dr., Suite 300
The Woodlands, Texas 77380

Re: Evaluation Summary
Earthstone Energy, Inc. Interests
Total Proved Reserves
Certain Properties in Texas
As of December 31, 2018

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Mr. Anderson:

As you have requested, this report was completed on February 11, 2019 for the purpose of submitting our estimates of proved reserves and forecasts of economics attributable to the *Earthstone Energy, Inc*. ("Earthstone") interests. This report covers all of Earthstone's proved reserves. 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, 2018, 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	13,916.8	408.3	14,325.1	44,708.9	59,034.0
Gas	- MMcf	25,063.3	1,046.9	26,110.2	87,107.0	113,217.3
NGL	- Mbbl	4,774.5	194.6	4,969.2	15,974.4	20,943.6
Net Revenue						
Oil	- M$	871,700.6	24,818.3	896,518.9	2,735,179.8	3,631,698.3
Gas	- M$	56,634.0	2,171.2	58,805.2	185,868.7	244,673.9
NGL	- M$	137,193.9	5,755.8	142,949.7	460,434.9	603,384.6
Severance Taxes	- M$	54,635.3	1,736.2	56,371.5	174,291.0	230,662.5
Ad Valorem Taxes	- M$	20,010.2	652.3	20,662.5	61,796.9	82,459.4
Operating Expenses	- M$	204,924.0	4,059.5	208,983.5	329,957.5	538,941.0
Other Deductions	- M$	42,432.6	1,317.9	43,750.5	109,618.9	153,369.4
Abandonment Costs	- M$	4,143.4	75.6	4,219.1	3,480.0	7,699.1
Investments	- M$	0.0	406.9	406.9	963,129.4	963,536.1
Future Net Cash Flow (BFIT)	- M$	739,383.2	24,496.9	763,879.8	1,739,209.9	2,503,089.3
Discounted @ 10%	**- M$**	**421,105.8**	**14,630.7**	**435,736.4**	**572,763.6**	**1,008,500.1**

The discounted future net cash flow shown above should not be construed to represent an estimate of the fair market value of the reserves by Cawley, Gillespie & Associates, Inc. ("CG&A").

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital 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.

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, 2018 were $65.56/BBL and $3.100/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 (Bloomberg) during 2018 and the base gas price is based upon Henry Hub spot prices (Platts Gas Daily) during 2018. NGL prices were adjusted on a per-property basis and averaged 43.9% 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 $61.52 per barrel for oil, $2.16 per MCF for natural gas and $28.81 per barrel for NGL. All economic factors were held constant in accordance with SEC guidelines.

Capital, Expenses and Taxes

Capital expenditures, 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. 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 182 proved undeveloped locations, all of which are commercial using required SEC pricing. 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, for both developed and 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 developed non-producing and 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. Further, the net cost of plugging and the salvage value of equipment at abandonment have been included herein.

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.

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 50 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

W. TODD BROOKER, P.E.
PRESIDENT

ROBERT P. BERGERON, JR., P.E.
RESERVOIR ENGINEER