SECURITIES & EXCHANGE COMMISSION EDGAR FILING

EARTHSTONE ENERGY INC

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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, 2014

Or

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

Commission File No. 001-35049

EARTHSTONE ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

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

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $0.001 par value per share	NYSE MKT

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 o 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 o 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 o

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 o

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, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer	❑	Accelerated filer	❑
Non-accelerated filer	❑ (Do not check if a smaller reporting company)	Smaller reporting company	☑

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

The aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price of $33.52 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 $41,493,391.

As of March 25, 2015 13,835,128 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for its 2015 Annual Meeting of Stockholders (the "Proxy Statement"), are incorporated by reference into Part III of this report Annual Report on Form 10-K.

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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," "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 or prospects are also forward-looking statements. Actual results could differ materially from those anticipated in 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:

- volatility and weakness in commodity prices for oil and natural gas and the effect of prices set or influenced by action of the Organization of Petroleum Exporting countries ("OPEC");
- changes in estimates of our proved reserves;
- our ability to replace our oil and natural gas reserves;
- declines in the values of our oil and natural gas reserves;
- the potential for production decline rates for our wells to be greater than we expect;
- the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves;
- our ability to acquire leases, supplies and services on a timely basis and at reasonable prices;
- the cost and availability of goods and services, such as drilling rigs and completion equipment;
- risks in connection with potential acquisitions and the integration of significant acquisitions;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and will divert management's time and energy;
- the possibility that anticipated divestitures may be delayed or may not occur or could be burdened with unforeseen costs;
- reductions in the borrowing base under our credit facility;
- risks incident to the drilling and operation of oil and natural gas wells;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on prices;
- significant competition for acreage and acquisitions, including competition which may be intense in resources play areas pending adequate commodity prices and reserve potential;
- the effect of existing and future laws, governmental regulations and the political and economic climates of the United States;
- our ability to attract and retain key members of senior management and key technical employees;
- changes in environmental laws and the regulation and enforcement related to those laws;
- the identification of and severity of 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 state, and federal 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 will worsen and that capital markets will be disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as Africa, the Middle East, and armed conflict or acts of terrorism or sabotage;

- the insurance coverage maintained by us 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; and
- our dependency on the skill, ability and decisions of third party operators of oil and natural gas properties in which we have a non-operated working interest.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph 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.

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.

Behind-pipe reserves – Those reserves expected to be recovered from completion interval(s) not yet open but still behind casing in existing wells. These reserves, if they meet the criteria for proved reserves, will be included in the PDNP category of our reserves.

BOE – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

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

Completion – The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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 – The act of making an oil and natural gas property more profitable, productive or useful.

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.

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. Greater horizontal exposure to a hydrocarbon bearing reservoir typically results in increased production rates and greater ultimate recoveries of hydrocarbons than vertical drilling.

Hydraulic fracture (Frac) – A well stimulation method by which fluid (approximately 95-98% water) and proppant (purposely sized particles used to hold open an induced fracture) are injected downhole and into the producing formation at high pressures and rates in order to exceed the rock strength and create a fracture such that the proppant material can be placed into the fracture to enhance the productive capability of the formation.

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

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

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

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

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.

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 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) estimated future abandonment costs, net of the estimated salvage value of related equipment, (ii) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (iii) 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 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 through existing wells 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.

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.

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.

Item 1. Business

Overview

Earthstone Energy, Inc. (together with our consolidated subsidiaries, the “Company,” “our,” “we,” “us,” “Earthstone” or similar terms), a Delaware corporation formed in 1969, is a growth-oriented independent oil and natural gas exploration and production company focused on the acquisition, development, exploration and production of onshore, crude oil and natural gas reserves. Our strategy, which is discussed in greater detail below, is to deliver competitive and sustainable rates of return to our stockholders by developing and acquiring oil and natural gas reserves through an active and diversified program that includes the acquisition, drilling and development of undeveloped leases, purchases of reserves and exploration activities that currently involve oil-weighted projects.

Our operations are all in the upstream segment of the oil and natural gas industry and are conducted onshore in the United States. Our asset portfolio includes activities in the Eagle Ford trend of south Texas and in the Williston Basin of North Dakota and Montana. These regions are a focus for us, as well as other areas in Texas and the Rocky Mountain states. We also own other operated and non-operated properties in east and south Texas, eastern Oklahoma and north Louisiana, which are currently contributing to cash flow, but may be divested in the future. We have accumulated approximately 27,000 net leasehold acres in the Eagle Ford trend of south Texas, including 23,900 net leasehold acres in the crude oil window in Fayette County and Gonzales County and 3,100 net leasehold acres located in the natural gas and condensate window in La Salle County. We serve as the operator for substantially all of our Fayette County and Gonzales County acreage with working interests ranging from 38% to 50% and we are a non-operator with respect to our La Salle County acreage with working interests ranging from 10% to 15%. We are also non-operator with respect to our properties in the Williston Basin. We continuously evaluate opportunities to expand our acreage and our producing assets through acquisitions. Our successful acquisition of assets will depend on the opportunities and the financing alternatives available to us at the time we consider such opportunities.

Our corporate headquarters is located in The Woodlands, Texas. We also have an operating office in Denver, Colorado and two field offices in south Texas. Our common stock is traded on the NYSE MKT under the symbol ESTE.

Recent Developments

Acquisitions

On December 19, 2014, we acquired three operating subsidiaries of Oak Valley Resources, LLC, a privately-held Delaware limited liability company (“OVR”), in exchange for shares of our common stock (the “Exchange”), which resulted in a change of control. Pursuant to the Exchange Agreement, OVR contributed to us the membership interests of its three subsidiaries, Oak Valley Operating, LLC (“OVO”), EF Non-Op, LLC (“EF Non-Op”) and Sabine River Energy, LLC (“Sabine”), each a Texas limited liability company (collectively “Oak Valley”), in exchange for approximately 9.124 million shares, representing 84% of our common stock. The Exchange has been accounted for as a reverse acquisition whereby Oak Valley is considered the acquirer for accounting purposes. All historical financial information contained in this report is that of OVR and its subsidiaries.

Upon the closing of the Exchange, we changed our fiscal year from March 31 to December 31 in order for our fiscal year end to correspond with the fiscal year end of OVR and its subsidiaries.

Immediately following the exchange, we acquired an additional 20% undivided ownership interestin certain crude oil and natural gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of approximately 2.957 million shares of our common stock (the “Contribution Agreement”) to Flatonia Energy, LLC (“Flatonia”), increasing our ownership in these properties from a 30% undivided ownership to a 50% undivided ownership interest. As a result of the share issuance to Flatonia, OVR’s ownership in us decreased from 84% to 66%.

For a detailed discussion of these transactions, see “Note 3 – Acquisitions and Divestitures” within the Notes to the Consolidated Financial Statements included in Part II Item 8. Financial Statements and Supplementary Data of this report.

Bank of Texas Credit Facility

In connection with the closing of the OVR and Flatonia transactions described above, on December 19, 2014, we entered into a credit agreement providing for a $500.0 million four-year senior secured revolving credit facility (the “Credit Agreement”) with BOKF, NA dba Bank of Texas (“Bank of Texas”), as agent and lead arranger, and Wells Fargo Bank, National Association (“Wells Fargo”), as syndication agent, and the Lenders signatory thereto (collectively with Bank of Texas and Wells Fargo, the “Lender”).

The initial borrowing base of the Credit Agreement is $80.0 million and is subject to redetermination on the first business day of May and November of each year. At the option of the borrower, the amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate (“LIBOR”) plus the applicable utilization margin of 1.50% to 2.50% or (b) the base rate plus the applicable utilization margin of 0.50% to 1.50%. Principal amounts outstanding under the credit facility are due and payable in full at maturity on December 19, 2018. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of our assets. Additional payments due under the Credit Agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate ranges from 0.375% to 0.50% per year, depending upon the unutilized portion of the borrowing base in effect from time to time. We are also required to pay customary letter of credit fees. For additional details, see “Note 8 – Long-Term Debt” in the Notes to the Consolidated Financial Statements included in Part II Item 8. Financial Statements and Supplementary Data.

Our Business Strategy

We pursues a value-driven growth strategy focused on projects that we believe will generate strong and predictable rates of return and increases in stockholder value. We believe that we should be the operator of the majority of our properties in order to control costs and direct the efficient development of such properties in an effort to optimize investment returns and profitability. We also believe that a reasonable level of diversification in our asset base is preferable to that of a single basin focused company as it may provide us the ability to take advantage of regional changes in realized prices, service costs, service availability and numerous other factors that may affect the most cost-efficient and economic development of our assets. Management concentrates on building production, reserves and cash flows while continually seeking to expand our undeveloped acreage and drilling inventory in select targeted areas. Further expansion of our asset base will be achieved through cost efficient development, exploitation and operation of our current assets and acreage and through additional leasing, acquisitions, development drilling and exploration activities, currently directed toward oil-weighted projects. Finally, management intends to pursue corporate and asset acquisition opportunities.

Our business strategy includes the following:

- continuing the cost-effective development and exploitation of existing acreage positions with a particular attention to properties located in the Eagle Ford, Austin Chalk, Bakken and Three Forks formations;
- expanding our acreage positions and drilling inventory in our areas of primary interest through acquisitions and farm-in opportunities, with an emphasis on operated positions and selective non-operated participations with capable operators;
- generating additional exploration and development projects in our areas of primary interest;
- pursuing value-accretive corporate merger and acquisition opportunities;
- selectively divesting non-core assets in order to streamline operations and utilize capital and human resources most effectively; and
- obtaining additional capital, as needed, through the issuance of equity and debt securities or by soliciting industry or financial participants to jointly develop and/or acquire assets.

Our fundamental operating and technical strategy is complemented by our focus on increasing stockholder value by:

- maximizing profit margins;
- controlling capital expenditures and operating and administrative costs;
- promoting industry or institutional participants into projects to manage risk, enhance rates of return and lower net finding and development costs; and
- maintaining a sound capital structure.

Management believes its strategy is appropriate because it:

- addresses multiple risks of oil and gas operations while providing equity holders with upside potential; and
- results in “staying power,” which management believes is essential to mitigate the adverse impacts of historically volatile commodity prices and financial markets.

Our Operations

We are the operator of properties containing approximately 67% of our proved oil and natural gas reserves and 79% of our proved PV-10 as of December 31, 2014. As operator, we are able to directly influence exploration, development and production of operations of our operating properties. 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 that we believe have the potential to increase stockholder value.

As is common in the industry, we participate in non-operated properties on a selective basis. 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.

Description of Major Properties

The following is a brief description of our primary oil and natural gas properties and current focus areas. We also own operated and non-operated properties located in east and south Texas, eastern Oklahoma and north Louisiana.

Fayette County, Texas and Gonzales County, Texas

Operated Eagle Ford

As of December 31, 2014, we had accumulated approximately 47,900 gross (23,900 net) leasehold acres in Gonzales and Fayette 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, Upper Eagle Ford, Buda, Wilcox and Edwards formations. We serve as the operator with a 50% undivided ownership interest in substantially all of the acreage.

As of December 31, 2014, we operated 49 gross Eagle Ford wells and five gross Austin Chalk wells and had non-operated interests in two gross producing Eagle Ford wells and two gross producing Austin Chalk wells. Seventeen gross Eagle Ford wells were in the process of being drilled or were waiting on completion. Our plan is to complete approximately five wells per quarter throughout 2015. We have identified a total of approximately 217 gross Eagle Ford drilling locations. The number of Eagle Ford locations could potentially increase subject to future down spacing initiatives. In addition, because our acreage position is prospective for the Austin Chalk, Upper Eagle Ford, Buda, Wilcox and Edwards formations, we may have future additional economic locations. The majority of our acreage is covered by a 173 square mile 3-D seismic survey, which is being used to effectively develop the Eagle Ford and identify Austin Chalk locations and other economic opportunities.

We are currently budgeting $7.1 million to $7.5 million per well to drill and complete Eagle Ford wells with lateral lengths of approximately 6,000-7,000 feet, and $4.0 million to $4.5 million per well to drill and complete Austin Chalk wells with lateral lengths of approximately 13,000 feet.

Non-Operated Eagle Ford

We have a non-operated position in approximately 26,300 gross acres in two areas within the Hawkville Field in La Salle County, Texas. The acreage is operated by BHP Billiton and Lewis Petro Properties, Inc. and is prone to natural gas and condensate produced from the Eagle Ford formation. The two areas are summarized below:

a) White Kitchen – We have a 15% working interest in approximately 7,600 gross acres, all of which is held by production. As of December 31, 2014, 30 gross wells were producing, and we have identified approximately 40 additional drilling locations.

b) Martin Ranch – We have a 10% working interest in approximately 18,700 gross acres. As of December 31, 2014, 30 gross wells were producing, and we have identified approximately 150 additional drilling locations in the acreage. BHP Billiton is required to drill nine wells prior to May 2015, and six wells between May 2015 and May 2016, at which point a new drilling commitment, if any, may be contemplated. We are currently participating in in the completion of 13 gross wells which are expected to begin producing during the first half of 2015.

Williston Basin, North Dakota and Montana.

We have a non-operated position in approximately 10,900 net acres in the Williston Basin of North Dakota and Montana. Our most active areas within the basin include the Banks, Indian Hill and Camel Butte Fields in McKenzie County, North Dakota and fields within Dunn County, North Dakota. In the Banks Field, we have an average working interest of 3.6% in 69 horizontal Bakken/Three Forks wells that are primarily operated by Statoil. In the Indian Hill and Camel Butte Fields, we have an average working interest of 1.6% in five horizontal Bakken/Three Forks wells operated by various parties. In Dunn County, North Dakota, we have an average working interest of 1.2% in seven horizontal Bakken/Three Forks wells that are operated by Marathon Oil Corporation. In Divide County, North Dakota and Sheridan County, Montana, we have an interest in undeveloped acreage that is held by a producing vertical wells. The acreage is prospective for the Bakken and/or Three Forks formation.

Competition

The domestic oil and natural gas business is intensely competitive in the exploration for and acquisition of reserves and in the producing and marketing of oil and natural gas production. Our competitors include national oil companies, major oil and natural gas companies, independent oil and natural gas companies, individual producers, natural gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay 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.

Operational Risks

Oil and natural gas exploration and development involves 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 discover or acquire 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 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 will 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 or cash flows. For further discussion of risks see Item 1A. Risk Factors of this report.

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 such properties. Our 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, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase 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 communitization 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 size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including 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 include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual 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, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns 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, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration 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.

Environmental Regulations

Our operations are 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, commonly referred to as 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 regulate the permitting, construction and operation of a 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.

New programs and changes in existing programs, however, may address various aspects of our business including natural occurring radioactive materials, 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, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes 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 disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to 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 some 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.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and natural gas wastes and reclassify them as hazardous wastes. If such proposals were to be enacted, they could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. 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

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA"), the Underground Injection Control ("UIC") regulations promulgated under the SDWA 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. 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 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. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state and federal jurisdictions. 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 depth to stimulate oil and natural gas production.

Under the direction of Congress, the EPA has undertaken a study of the effect of hydraulic fracturing on drinking water and groundwater. The EPA has also announced its plan to propose pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations. Congress may consider legislation to amend the SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, have issued similar disclosure rules. Several environmental groups have also petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

Air Emissions

The federal Clean Air Act and comparable state laws regulate 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 federal 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.

Recently, the EPA issued four new regulations for the oil and natural gas industry, including: a new source performance standard for volatile organic compounds ("VOCs"); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

In December 2014, the EPA proposed to lower the existing 75 parts per billion ("ppb") national ambient air quality standards ("NAAQS") for ozone under the federal Clean Air Act to a range within 65-70 ppb. The EPA is also taking public comment on whether the ozone NAAQS should be revised to as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the EPA has issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from our oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA has issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, President Obama released a Strategy to Reduce Methane Emissions in March 2014. Consistent with that strategy, the EPA has announced that it intends to issue a proposed rule in 2015 to set standards for methane and VOC emissions from new and modified oil and natural gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. As another prong of the President's strategy, the federal Bureau of Land Management ("BLM") is expected to propose standards in 2015 to reduce venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and natural gas industry as compared to 2012 levels. In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or 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. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. This process has the potential to delay the development of future oil and natural gas projects.

Threatened and endangered species, migratory birds and natural resources

Various state and federal 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, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. 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.

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 govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act and may require that information be provided to state and local government authorities and the public.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupations Safety and Health Act and comparable state statues that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Employees

As of December 31, 2014, we had 50 full-time and 2 part-time employees, 40 of which are management, technical and administrative personnel, and 12 of which are field operations employees. Contract personnel perform some technical and administrative tasks and operate some of our producing fields under the direct supervision of our employees. No employees are covered under a collective bargaining agreement nor are any employees represented by a union. The Company considers all relations with its employees to be good.

Office Leases

We lease 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
Denver, Colorado	7,000 sq. ft.	April 30, 2016	Office
Denver, Colorado	700 sq. ft.	April 30, 2015	Office

During 2014, aggregate rental payments for our office facilities totaled approximately $0.3 million.

Executive Officers of the Company

Name	Age	Position
Frank A Lodzinski	65	President and Chief Executive Officer
Ray Singleton	64	Executive Vice President, Northern Region
Robert J. Anderson	53	Executive Vice President, Corporate Development and Engineering
Steve C. Collins	50	Executive Vice President, Completions and Operations
Chris E. Cottrell	54	Executive Vice President, Land and Marketing
Timothy D. Merrifield	59	Executive Vice President, Geological and Geophysical
Francis M. Mury	63	Executive Vice President, Drilling and Development
G. Bret Wonson	37	Vice President, Principal Accounting Officer
Neil K. Cohen	32	Vice President, Finance and Treasurer

Frank A. Lodzinski has served as our Chairman, President and Chief Executive Officer since December 2014. Previously, he served as President and Chief Executive Officer of Oak Valley Resources, LLC from its formation in December 2012 until the closing of its strategic combination with us in December 2014. Prior to Oak Valley Resources, LLC, Mr. Lodzinski was Chairman, President and Chief Executive Officer of GeoResources, Inc. from April 2007 until its merger with Halcón Resources Corporation in August 2012 and from September 2012 until December 2012 he conducted preformation activities for Oak Valley Resources, LLC. He has over 43 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 since its formation. The Southern Bay entities were merged into GeoResources in April 2007. He holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan.

Ray Singleton is a petroleum engineer with over 37 years of experience in the oil and gas industry. He has been one of our directors since July 1989 and was our President and Chief Executive Officer from March 1993 until December 2014. Since December 2014, he has served as our Executive Vice President, Northern Region. Mr. Singleton us in 1988 as a Production Manager/Petroleum Engineer. From 1983 until 1988, he owned and operated a small engineering consulting firm (Singleton & Associates) serving the needs of 40 small oil & gas clients. During this period, he was engaged by the Company on various projects in south Texas and the Rocky Mountain region. Mr. Singleton began his career with Amoco Production Company in 1973 as a production engineer in Texas. He was subsequently employed by the predecessor of Union Pacific Resources as a drilling, completion and production engineer from 1980 to 1983. His professional experience includes acquisition evaluation and economics, reserve engineering and drilling, completion and production engineering in both Texas and the Rocky Mountain region. In addition, he possesses over 20 years of C-Level experience and has an intimate knowledge of the Company's legacy Rocky Mountain properties. Mr. Singleton received a B.S. degree in Petroleum Engineering from Texas A&M University in 1973, and received an MBA from Colorado State University's Executive MBA Program in 1992.

Robert J. Anderson is a petroleum engineer with over 28 years of diversified domestic and international oil and gas experience. He has served as our Executive Vice President, Corporate Development and Engineering since December 2014. Previously, he served in a similar capacity with Oak Valley Resources, LLC from March 2013 until the closing of its strategic combination with the Company in December 2014. Prior to joining Oak Valley Resources, LLC, he served from August 2012 to February 2013 as Executive Vice President and Chief Operating Officer of Halcón Resources Corporation. Mr. Anderson was employed by GeoResources, Inc. from April 2007 until its merger with Halcón Resources 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.

Steven C. Collins is a petroleum engineer with over 26 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 Resources, LLC from its formation in December 2012 until the closing of its strategic combination with the Company December 2014. Prior to employment by Oak Valley Resources, LLC, he served from August 2012 to November 2012 as a consultant to Halcón Resources. Mr. Collins was employed by GeoResources from April 2007 until its merger with Halcón Resources in August 2012 and directed all field operations, including production, workover, recompletion, and drilling 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.

Chris E. Cottrell has been employed in various aspects of land management and commodity marketing activities since 1983. He has served as our Executive Vice President, Land and Marketing since December 2014. Previously, he served in a similar capacity with Oak Valley Resources, LLC from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Prior to employment by Oak Valley Resources, LLC, he was employed by GeoResources from April 2007 until its merger with Halcón Resources in August 2012, ultimately serving as Vice President of Land and Marketing, responsible for land and operating contract matters including oil and gas marketing, land and lease records, title and division orders. In addition, he was actively involved in due diligence associated with business development matters. He has held previous roles at AROC, Texoil, Williams Exploration, Ashland Exploration, American Exploration, Belco Energy, and Citation Oil & Gas. Mr. Cottrell graduated with a B.B.A. degree in Petroleum Land Management from the University of Texas.

Timothy D. Merrifield has over 35 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 Resources, LLC from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Prior to employment by Oak Valley Resources, LLC, he served from August 2012 to November 2012 as a consultant to Halcón Resources upon its merger with GeoResources in August 2012. From April 2007 to August 2012, Mr. Merrifield led all geology and geophysics efforts at GeoResources. He has held previous roles at AROC, Force Energy, Great Western Resources and other independents. His domestic experience includes Texas, Louisiana (onshore and offshore), North Dakota, Montana, New Mexico, Rocky Mountain states, and the Mid-Continent. In addition, he has international experience in Peru and the East Irish Sea. Mr. Merrifield attended Texas Tech University.

Francis M. Mury has over 40 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 Resources, LLC from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. Prior to employment by Oak Valley Resources, LLC, he was employed by GeoResources from April 2007 until its merger with Halcón Resources 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.

G. Bret Wonson has over 13 years of professional experience. Hehas served as our Vice President, Principal Accounting Officer since December 2014. Previously, he served in a similar capacity with Oak Valley Resources, LLC from February 2013 until the closing of its strategic combination with the Company in December 2014. Prior to Oak Valley Resources, LLC, he served from August 2012 to February 2013 as Assistant Controller at Halcón Resources Corporation upon its merger with GeoResources, Inc. in August 2012. From February 2012 to August 2012 and from April 2008 to November 2010, Mr. Wonson was Corporate Controller and Controller of GeoResources, respectively. From December 2010 to January 2012, he was an Assistant Controller at Valerus Compression. He has held previous roles at Arthur Andersen, Grant Thornton, and BP. Mr. Wonson holds a bachelor's degree in Accounting from Mississippi State University and a master's degree in Accounting from the University of Alabama. Mr. Wonson is a Certified Public Accountant in the State of Texas.

Neil K. Cohen has over 11 years of professional experience. He has served as our Vice President, Finance, and Treasurer since December 2014. Previously, he served in a similar capacity with Oak Valley Resources, LLC from its formation in December 2012 until the closing of its strategic combination with the Company in December 2014. He is primarily responsible for all corporate finance, capital markets, and investor relations activities. Prior to joining Oak Valley Resources, LLC, he served from September 2012 to December 2012 as a consultant to Texoil Energy, Inc. From February 2006 to October 2011, Mr. Cohen was employed by UBS Investment Bank as a member of the Global Energy Group, with exposure to all energy subsectors and a particular emphasis on exploration and production companies, and as a member of UBS' Debt Capital Markets Group, with a particular emphasis on investment grade energy and utility issuers. He has held previous roles at Merrill Lynch (Debt Capital Markets and Debt Derivatives Finance) and Hess Corporation (Finance). Mr. Cohen graduated with a B.S. degree in Finance from the University of Maryland.

There are no arrangements or understandings between any of Messrs. Lodzinski, Singleton, Anderson and Wonson, or any other person pursuant to which such person was selected as an officer. None of Messrs. Lodzinski, Singleton, Anderson and Wonson has any family relationship with any director or other executive officer of the Company or any person nominated or chosen by the Company to become a director or executive officer.

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 Securities and Exchange Commission ("SEC"). Information filed with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also 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

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under “Cautionary Statement Concerning Forward-Looking Statements” and other information included and incorporated by reference into this report.

Oil and natural gas prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. These prices also affect the amount of cash flow available for our capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our credit agreement will be subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce, resulting in an adverse effect on the quantities and the value of our reserves.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and determine oil prices and production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as northern Africa and the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;
- the price of foreign imports; and
- worldwide economic conditions.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that 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 are 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 future oil and natural gas reserves and production and, therefore, our cash flow 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 flow 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 our reserves.

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC 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. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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 could materially affect the estimated quantities and the value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2014, approximately 56% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to 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 will likely 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 proved reserves will 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 proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, 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 average prices without giving effect to derivative transactions. 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 our incurrence of expenses in connection with the development and production of 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 us or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for federal 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 present value estimates included in this report which would could have a material effect on the value of our reserves.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, then we will be required to incur write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down 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 taken.
A write-down of the capitalized cost of individual oil and natural gas properties 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. A write-down could adversely affect the trading price of our common stock.

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 will 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.

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 we experience increases in the price of oil and/or natural gas or increases in the quantity of our estimated proved reserves.

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

The oil and gas industry is highly competitive. We compete with major integrated and larger independent oil and gas companies for the acquisition of desirable oil and gas properties and leases, for the equipment and services required to develop and operate properties, and in the marketing of oil and gas to end-users. Many competitors have financial and other resources that are substantially greater than ours, which will make any acquisition of acreage or producing properties at economic prices difficult. In addition, many larger competitors may be better able to respond to factors that affect the demand for oil and natural gas production, such as changes in worldwide oil and natural gas prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. 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 and we may be at a competitive disadvantage to companies with larger financial resources than ours.

A failure to complete additional acquisitions would limit our growth.

Our future success is highly dependent on our ability to find, acquire or develop economically recoverable oil and natural gas reserves. Without continued successful acquisition, exploration or development projects, our current 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, when attractive opportunities arise, is an important component of our 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 will be more difficult to replace and increase our reserves, and an inability to replace our reserves would 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 will 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 the business or property to be acquired may not uncover all existing or relevant data, obligations or actual or contingent liabilities that could adversely impact the 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 problems, title defects or other liabilities. If we acquire properties on an "as-is" basis, we will 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, 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. In addition, we may face greater risks to the extent we acquire properties in areas outside of areas in which we currently operate because we may be less familiar with operating, regulatory and other issues specific to those areas.

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 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 the acquired properties.

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

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

- unanticipated, abnormally pressured formations;
- mechanical difficulties, such as stuck drilling and service tools and casing collapse;
- 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 liabilities. Although we believe we are adequately insured for replacement costs of our wells and associated equipment, the payment of any of these liabilities could reduce the funds available for exploration, development, and acquisition, or could result in a loss of our properties.

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

Our operations involving the exploration and production of hydrocarbons are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety, and related employee health and safety matters. Laws and regulations applicable to us include those relating 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;
- emissions into the air;
- unitization and pooling of properties;
- 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 all of these laws and regulations are a significant cost of doing business. Failure to comply with these 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. Strict liability 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 plugging and abandonment obligations are and will continue to be substantial and 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 they will be material. Environmental risks are generally not fully insurable.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, natural gas venting and transportation restrictions based on crude oil volatility, could result in increased costs and additional operating restrictions or delays in our production of oil and natural gas and lower returns on our capital investments.

Bills have been introduced in the U.S. Congress and in various state legislatures to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA") or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale and tight sand formations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate. Sponsors of such bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, surface waters, and other natural resources, and threaten health and safety. In addition, The EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, with a draft of the study anticipated to be available by March 2015, and legislation has been proposed before Congress to provide for federal regulation of hydraulic fracturing and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process, which legislation could be reintroduced in the current session of Congress. Further, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Certain states and localities have also considered or imposed reporting and other operational obligations relating to the use of hydraulic fracturing techniques.

Certain states, including Texas, where we conduct operations, have adopted, and other states are considering the adoption of, regulations that impose new or more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have resulted in the imposition of bans on hydraulic fracturing. Some local jurisdictions, including Dallas, Texas, have adopted regulations restricting hydraulic fracturing. The proliferation of regulations may limit our ability to conduct hydraulic fracturing, which is an essential component of our current operations in the Eagle Ford trend of south Texas and in the Williston Basin of North Dakota and Montana.

Additional legislation or regulation could make it easier for parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process adversely affect groundwater. There has also been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for adverse impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated in Texas and other states implicating hydraulic fracturing practices.

Legislation, regulation, litigation and enforcement actions at the federal, state or local level that restrict hydraulic fracturing services could limit the availability and raise the cost of such services, delay completion of new wells and production of our oil and natural gas, lower our return on capital expenditures and have a material adverse impact on our business, financial condition, results of operations and cash flows and quantities of oil and natural gas reserves that may be economically produced.

Certain states, including North Dakota where we conduct operations, and have interest in numerous non-operated wells, and intend to expand our presence in the future have adopted, and other states are considering the adoption of, regulations that impose new or more stringent permitting, disclosure and threshold requirements on the intentional or inadvertent venting of natural gas. Such efforts have resulted in the delay of certain drilling and/or completion operations until additional natural gas pipelines are built or sufficient transportation capacity is available. The proliferation of these regulations in North Dakota and in other states may limit or delay our ability to conduct operations in a timely manner.

The state of North Dakota has issued new conditioning standards requiring certain crude oils produced in North Dakota to be conditioned to remove lighter, volatile hydrocarbons, and thereby make the oil safer to transport by railroad. The new standards seek to address safety concerns stemming from several recent train derailments in U.S. and Canada. The new standard establishes a goal of achieving a vapor pressure of no greater than 13.7 pounds per square inch (psi) rather than the current national standard of 14.7 psi or less. The adoption of these regulations and/or their proliferation to other states may require the installation of new and more costly control equipment, increase the cost of production operations, increase the costs incurred by oil transporters and thereby decrease the price we receive for crude oil sold in North Dakota.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change and the Kyoto Protocol address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory regimens.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration is attempting to address climate change through a variety of administrative actions. The EPA has issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, the President released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA has released five draft white papers on methane and volatile organic compound emissions and mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities and natural gas production and transmission facilities. Building on its white papers and public input on those documents, the EPA has announced that it intends to issue a proposed rule in the summer of 2015 to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas transmissions sources. Also as part of the President's strategy, the BLM is expected to propose standards for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls or other compliance costs, and reduce demand for our products.

The ongoing implementation of federal legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation. The CFTC, in coordination with the SEC and various U.S. federal banking regulators, has issued regulations to implement the so-called "Volcker Rule" under which banking entities are generally prohibited from proprietary trading of derivatives. Although conditional exemptions from this general prohibition are available, the Volcker Rule may limit the trading activities of banking entities that have been counterparties to our derivatives trades in the past. Also, a provision of the Dodd-Frank Act known as the "swaps push-out rule" may require some of the banking counterparties to our commodity derivative contracts to "push out" some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The CFTC also has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin and position limits; 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 Dodd-Frank Act and the CFTC regulations may require compliance with margin requirements and

with certain clearing and trade-execution requirements in connection with certain of our derivative activities. Also, 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. It is possible that the CFTC, in conjunction with the U.S. federal banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which we would be required to post collateral.

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 may encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts, and potentially increase our exposure to less creditworthy counterparties. 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. 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.

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

Oil and gas exploration and development is 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 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 incentive programs related to our oil and gas properties and the oil and 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.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil and natural gas prices, these transactions may limit our potential gains and increase our potential losses if oil and natural gas prices, were to rise substantially over the price established by the hedges. In addition, these transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

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 operations 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 oil and natural gas we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our oil and natural gas 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. These are risks for which we generally will not maintain insurance.

Use of debt financing may adversely affect our strategy.

We intend to use debt to fund a portion of our future acquisition and operating activities. Any temporary or sustained inability to service or repay debt will materially adversely affect our ability to access the financing market and to 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 will be controlled by third parties that may not allow us to proceed with planned explorations and expenditures. Activities on operated properties could also be limited or subject to penalties.

While we intend to operate the majority of our properties, we are not currently the operator of many of our existing properties and, therefore, may not be able to influence production operations or further development activities. At present, we operate wells comprising approximately 64% of our total proved reserves. Joint ownership is customary in the oil and 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 the proposed activity or decline to participate. 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 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 exploration, exploitation, development or acquisition activities. The success and timing of exploration, exploitation and development activities on properties operated by others depend upon a number of factors that may be outside our control, including:

- 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 and other liabilities in excess of our proportionate interest in the property.

Because we cannot control the timing and accuracy of financial information regarding the results of operations on properties we do not operate, our ability to timely and accurately report our results of operations and financial position may be adversely affected.

For properties we do not operate, we are dependent on the operators of such properties for financial information regarding the results of operations. Any delay in receipt of such information or inaccuracies in calculating and reporting such information by the operator would adversely affect our ability to timely and accurately report our results of operations and financial condition.

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, conduct reservoir modeling and reserve estimation, for compliance report.

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 stockholder, analyze seismic and drilling information, estimate quantities of oil and 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 and development 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, also has increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or 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. 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.

Risks Related to the Ownership of our Common Stock

We are a "controlled company" within the meaning of the NYSE MKT rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements. As a result, our stockholders do not have the same protections afforded to stockholders of companies that are subject to such requirements.

OVR beneficially owns a majority of our common stock. As a result, we are a "controlled company" within the meaning of the NYSE MKT corporate governance standards. Under the NYSE MKT 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 MKT corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

We are currently utilizing, and intend to continue to utilize, the exemption relating to a majority of our board of directors not being independent, the compensation committee, the nominating committee, and we may utilize this exemption for so long as we are a controlled company. Accordingly, our stockholders do not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE MKT.

OVR holds a substantial majority of our common stock.

OVR holds the majority of the outstanding shares of our common stock. OVR is entitled to act separately in its own interest with respect to its shares of our common stock, and it has the voting power to elect all of the members of our board of directors and thereby control our management and affairs. In addition, OVR has the ability to determine the outcome of all matters requiring stockholder approval, including mergers and other material transactions, and to cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company. The existence of a significant stockholder may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as OVR continues to control a significant amount of our common stock, OVR will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of OVR may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

Our common stock price has been and is likely to continue to be highly volatile.

The trading price of our common stock is subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that are beyond our control.

In addition, the stock market in general and the market for oil and natural gas exploration companies, in particular, have experienced large price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common stock regardless of our actual operating performance. In the past, following periods of volatility in the overall market and in the market price of a company's securities, securities class action litigation has been instituted against certain oil and natural gas exploration companies. If this type of litigation were instituted against us following a period of volatility in our common stock trading price, it could result in substantial costs and a diversion of our management's attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Oil and Natural Gas Reserves

All of our oil and natural gas reserves are located in the United States. 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 reserves, including information on future net cash flows and the standardized measure of discounted future net cash flows, please refer to the "Supplemental Data on Oil and Gas Exploration and Producing Activities (Unaudited)" within Part II, Item 8 of the Notes To Consolidated Financial Statements of this report.

2014 Increases in proved reserves

From January 1, 2014 to December 31, 2014, our proved reserves increased as follows:

1. Total proved reserves increased 94% from 11,431 MBOE to 22,192 MBOE;
2. Proved developed reserves increased 164% from 3,706 MBOE to 9,800 MBOE; and
3. Proved undeveloped reserves increased 60% from 7,725 MBOE to 12,392 MBOE.

These significant increases were attributable to a combination of (i) drilling and development and (ii) the strategic combination with OVR and the Flatonia acquisition, which occurred in 2014 and are more fully described elsewhere in this report.

Proved Reserves as of December 31, 2014

The below table sets forth a summary of our estimated crude oil, natural gas and natural gas liquids reserves as of December 31, 2014 based on the reserve report prepared by CG&A. Proved reserves are estimated based on the unweighted average beginning-of-month-prices during the 12-month period for the year. All prices and costs associated with operating wells were held constant in accordance with the SEC guidelines.

	Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	Total (MBOE)	Present Value Discounted at 10% ($ in thousands)
Proved developed	6,093	16,214	1,005	9,800	$ 235,431
Proved undeveloped	7,710	22,365	954	12,392	109,369
Total proved	13,803	38,579	1,959	22,192	$ 344,800

Present Value Discounted at 10% ("PV-10") is a non-GAAP measure that differs from the GAAP measure "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 PV-10 value 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 discern presently. 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)	$ 344,800
Future income taxes, discounted at 10%	(88,944)
Standardized measure of discounted future net revenues	$ 255,856

Proved Undeveloped Reserves ("PUDs")

Proved undeveloped reserves increased 4,667 MBOE or 60%, for the year ended December 31, 2014 compared to the year ended December 31, 2013. Revisions of prior estimates reflect our operational results, drilling activities, and on-going evaluation of our asset portfolio. Certain previously booked PUDs were reclassified as proved developed reserves due to successful drilling efforts. Revisions of prior estimates also include certain PUDs that were reclassified to unproved categories due to development plan changes and the impact of changes in commodity prices. In accordance with our 2014 year-end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within the next five years.

The following table details the changes in our proved undeveloped reserves for year ended December 31, 2014 (*in MBOE*):

Beginning proved undeveloped reserves at January 1, 2014	7,725
Conversions to developed	(1,306)
Extensions and discoveries	850
Purchases of reserves in place	4,451
Revisions of prior estimates	672
Ending proved undeveloped reserves at December 31, 2014	12,392

Conversions. In 2014, approximately 63% of the reserve conversions occurred in our operated Eagle Ford / Austin Chalk properties in Fayette and Gonzales Counties, Texas, with the remaining occurring in our non-operated Eagle Ford project in La Salle County, Texas.

Extensions and discoveries. During 2014, we added 850 MBOE of PUDs through extensions and discoveries, primarily as a result of successful drilling in our operated Eagle Ford properties in Fayette and Gonzales Counties, Texas.

Purchases. In December 2014, we acquired additional interests in our operated Eagle Ford properties in Fayette and Gonzales Counties, Texas and acquired properties in the Williston Basin of North Dakota and Montana as part of our Oak Valley and Flatonia acquisitions as disclosed elsewhere in this report.

Revisions. In 2014, the upward revisions of 672 MBOE to PUD reserves occurred primarily as a result of increased natural gas prices, which increased the number of economic PUD locations.

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. Robert D. Ravnaas, President of CG&A. He earned a Bachelor of Science degree with special honors in Chemical Engineering from the University of Colorado at Boulder in 1979 and a Master of Science degree in Petroleum Engineering from the University of Texas at Austin in 1981. Mr. Ravnaas is a Registered Professional Engineer in Texas and has more than 30 years of experience in the estimation and evaluation of oil and natural gas reserves. He is also a member of the Society of Petroleum Geologists and the Society of Professional Well Log Analysts.

Mr. Anderson, our Executive Vice President responsible for reservoir engineering, is a qualified reserve estimator and auditor and is primarily responsible for overseeing CG&A during the preparation of our reserve report. 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 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 28 years of practical experience in estimating and evaluating reserve information with more than five 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 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," 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 Executive Vice President responsible for reservoir engineering. 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 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 and natural gas and natural gas liquids ("NGLs") produced and sold by us for the years ended December 31, 2014, 2013, and 2012, the average sales price per unit sold and the average production cost per unit are presented below.

	Years Ended December 31,		
	2014	2013	2012
Sales Volumes:			
Oil (MBbl)	403	163	90
Natural Gas (MMcf)	2,132	2,635	2,298
NGL (MBbl)	124	134	76
Total (MBOE)*	882	737	549
Average sale price:			
Oil per Bbl	$ 86.29	$ 98.32	$ 96.00
Natural Gas per Mcf	$ 4.39	$ 3.69	$ 2.64
NGL per BOE	$ 28.29	$ 28.88	$ 31.00
BOE	$ 53.99	$ 40.22	$ 31.13
Production cost per BOE**	$ 11.75	$ 11.23	$ 11.86

* 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). Natural gas liquids have been converted to MBbls.

** Excludes ad valorem taxes (which are included in lease operating expenses in our Consolidated Statements of Operations) and severance taxes. Ad valorem taxes included in lease operating expenses were $0.5 million, $0.5 million and $0.3 million in 2014, 2013 and 2012, respectively.

As of December 31, 2014, three fields accounted for 65% of our total estimated proved reserves. Two of those fields, Southern Bay Eagle Ford and Eagleville, which were acquired during the year ended December 31, 2013, accounted for 37% and 16%, respectively, of our total estimated proved reserves. The third field, Hawkville, was 12% of our total estimated proved reserves. No other single field accounted for 15% or more of our total estimated proved reserves for the years ended December 31, 2014, 2013 or 2012. The net

quantities of oil, natural gas and NGLs produced and sold by us from these significant fields for each of the years ended December 31, 2014, 2013 and 2012, the average sales price per unit sold and the average production cost per unit are presented below.

Southern Bay Eagle Ford Field

	Years Ended December 31, 2014	2013
Sales Volumes:		
Oil (MBbls)	210	46
Natural Gas (MMcf)	85	16
NGL (MBbl)	23	5
Total (MBOE)*	247	54
Average sale price:		
Oil per Bbl	$ 87.75	$ 100.43
Natural Gas per Mcf	$ 4.25	$ 3.99
NGL per Bbl	$ 28.98	$ 34.28
BOE	$ 78.80	$ 90.31
Production cost per BOE**	$ 6.96	$ 9.51

* 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). NGLs have been converted to MBbls.

** Excludes ad valorem taxes and severance taxes.

Eagleville Field

	Years Ended December 31, 2014	2013
Sales Volumes:		
Oil (MBbls)	70	37
Natural Gas (MMcf)	25	11
NGL (MBbl)	7	4
Total (MBOE)*	81	42
Average sale price:		
Oil per Bbl	$ 84.58	$ 99.84
Natural Gas per Mcf	$ 4.36	$ 4.03
NGL per Bbl	$ 30.24	$ 34.43
BOE	$ 77.57	$ 90.93
Production cost per BOE**	$ 9.16	$ 4.95

* 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). NGLs have been converted to MBbls.

** Excludes ad valorem taxes and severance taxes.

	Years Ended December 31, 2014	2013	2012
Sales Volumes:			
Oil (MBbls)	34	56	69
Natural Gas (MMcf)	947	1,362	761
NGL (MBbl)	85	125	75
Total (MBOE)*	280	407	272
Average sale price:			
Crude Oil per Bbl	$ 82.34	$ 95.67	$ 96.53
Natural Gas per Mcf	$ 4.45	$ 3.72	$ 2.81
NGL per Bbl	$ 27.72	$ 28.40	$ 30.96
BOE	$ 33.62	$ 34.23	$ 41.12
Production cost per BOE**	$ 11.08	$ 8.70	$ 5.38

* 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). NGLs have been converted to MBbls.

** Excludes ad valorem taxes and severance taxes.

Our oil production is sold to large purchasers. Due to the quality and location of our oil production, we may receive a discount or premium from index prices or “posted” prices in the area. Our natural gas production is sold primarily to pipeline companies and/or gas marketers under short-term contracts at prices which are tied to the “spot” market for natural gas sold in the area.

The purchasers of our oil, natural gas and NGLs production consist primarily of independent marketers, major oil and natural gas companies and pipeline companies. In 2014 and 2013, one purchaser, United Energy Trading, LLC (“United”), accounted for 60% and 21%, of our oil, natural gas and NGLs revenues, respectively. United is expected to be a significant purchaser in the future as well. No other purchaser accounted for 10% or more of our oil, natural gas and NGLs revenues during 2014. , 2013 and 2012.

We hold working interests in oil and natural gas properties for which third parties serve as operator. The operator sells the oil, natural gas and NGLs to the purchaser, and collects and distributes the revenue to us. In 2014, one operator account for 20% of our total oil, natural gas and NGLs revenues. In 2013, two operators distributed 47% and 11% of our oil, natural gas and NGL revenues. In 2012, two operators distributed 65% and 18% of our oil, natural gas and NGLs revenues. No other operator accounted for 10% or more of our oil, natural gas and NGLs revenues during the years ended December 31, 2014, 2013 and 2012.

Gross and Net Productive Wells

As of December 31, 2014, our total gross and net productive wells were as follows:

Oil (1)		Natural Gas (1)		Total (1)	
Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
262	68	201	63	463	131

(1) A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractions of working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production. Horizontal re-entries of existing wells do not increase a well total above one gross well.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2014, we had estimated total gross and net developed and undeveloped leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated or permitted by state regulatory authorities.

Gross acres are those acres in which working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

State	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas	54,000	23,600	51,200	33,600	105,200	57,200
Oklahoma	16,200	13,900	—	—	16,200	13,900
Montana	7,100	2,100	10,000	2,000	17,100	4,100
North Dakota	25,300	2,600	5,800	1,600	31,100	4,200
Wyoming	1,100	100	5,700	800	6,800	900
Nebraska	-	-	29,100	11,100	29,100	11,100
All Others	4,200	3,200	42,700	400	46,900	3,600
Total	107,900	45,500	144,500	49,500	252,400	95,000

Exploratory Wells and Development Wells

Set forth below for the three years ended December 31, 2014 is information concerning the number of wells the Company drilled during the years indicated.

Year	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
	Productive	Dry	Productive	Dry	Drilled
2014	—	—	7.3	—	7.3
2013	0.2	—	2.8	—	3.0
2012	0.2	0.1	1.7	0.1	2.1

Present Activities

As of December 31, 2014, we had 17 gross (7.8 net) operated wells in the process of drilling or completing and 51 gross (2.2 net) non-operated well in the process of drilling or completing.

Item 3. Legal Proceedings

In the normal course of business, we may be involved in litigation and claims arising out of our operations. As of December 31, 2014, and through the filing date of this report, we are not aware of any such proceedings against us or contemplated to be brought against us.

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 common stock are traded on the NYSE MKT under the symbol "ESTE." The following table sets forth the reported high and low sales prices of our common stock for the period indicated:

	Common Stock Price	
Period	**High**	**Low**
2014		
First Quarter	$ 22.70	$ 17.48
Second Quarter	$ 34.63	$ 21.11
Third Quarter	$ 36.76	$ 27.96
Fourth Quarter	$ 27.25	$ 15.00
2013		
First Quarter	$ 18.50	$ 15.74
Second Quarter	$ 16.49	$ 13.26
Third Quarter	$ 17.20	$ 12.70
Fourth Quarter	$ 19.21	$ 16.06

Holders

As of March 23, 2015, there were approximately 2,000 holders of record of our common stock.

Dividend Policy

We have never paid dividends on our common stock and do not intend to pay a dividend in the foreseeable future. Furthermore, our credit agreement with our bank restricts the payment of cash dividends. The payment of future cash dividends on common stock, if any, will be reviewed periodically by our Board of Directors and will depend upon, but not 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 bank credit arrangements.

Unregistered Sale of Securities

On December 19, 2014, we closed (i) the transactions contemplated by the Exchange Agreement dated May 15, 2014 and as amended September 26, 2014 (the "Exchange Agreement") with OVR and (ii) the previously announced Contribution Agreement dated October 16, 2014 (the "Contribution Agreement"), by and among us, OVR, Sabine, OVO, Parallel Resources Partners, LLC, a Delaware limited liability company ("Parallel"), and Flatonia.

Pursuant to the Exchange Agreement, OVR, contributed to us membership interest in its three subsidiaries, OVO, Sabine and EF Non-Op, LLC, a Texas limited liability company, inclusive of producing assets, undeveloped acreage and approximately $130.0 million of cash , in exchange for the issuance of 9,124,452 shares (the "Exchange Shares") of Common Stock, to OVR (the "Exchange"). The issuance of the Exchange Shares was exempt from registration as a private placement under Section 4(a)(2) of the Securities Act, and Rule 506 promulgated thereunder, among other exemptions.

Pursuant to the Contribution Agreement, Sabine, acquired a 20% undivided ownership interest in certain oil and gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of 2,957,288 shares (the "Contribution Shares") of Common Stock to Flatonia (the "Contribution"). The issuance of Contribution Shares was exempt from registration as a private placement under Section 4(a)(2) of the Securities Act, and Rule 506 promulgated thereunder, among other exemptions.

Equity Compensation Plan Information

In December 2014, our stockholders approved and adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"), which was effective upon the December 19, 2014 closing of the Exchange Agreement and the 2014 Plan remain in effect until December 18, 2024. Under the 2014 Plan, we may grant stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards to our employees or those of our subsidiaries or affiliates as well as persons rendering consulting or advisory services and non-employee directors, subject to the conditions set forth in the 2014 Plan. Generally, all classes of our employees are eligible to participate in the 2014 Plan.

The 2014 Plan currently provides that a maximum of 750,000 shares of our common stock may be issued in conjunction with awards granted under the 2014 Plan. Awards that are forfeited under the 2014 Plan will again be eligible for issuance as though the forfeited awards had never been issued. Similarly, awards settled in cash will not be counted against the shares authorized for issuance upon exercise of awards under the 2014 Plan.

The 2014 Plan limits the aggregate number of shares of common stock that may be covered by stock options and/or stock appreciation rights granted to any eligible employee in any calendar year to 250,000 shares. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with awards (other than stock options or stock appreciation rights) granted to any eligible employee in any calendar year to 150,000 shares. The 2014 Plan also limits the maximum aggregate amount that may be paid in cash pursuant to awards (other than stock options or stock appreciation rights) made to any eligible employee in any calendar year to $2,000,000.

The following table sets forth information concerning our only compensation plan available to non-employee directors, officers, employees and consultants at December 31, 2014:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding option, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
2014 Long-Term Incentive Plan	—	$ —	750,000
Equity compensation plans not approved by security holders:	N/A	N/A	N/A

Repurchase of Equity Securities

We did not repurchase any of our shares of common stock during the quarter ended December 31, 2014.

Item 6. Selected Financial Data

The following selected financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations", and our consolidated financial statements and the accompanying notes thereto included elsewhere in this report. In accordance with generally accepted accounting practices in the United States ("GAAP") the financial information and financial statements included herein are those of OVR and its subsidiaries. Prior to the reverse acquisition OVR, and its subsidiaries were pass through entities for income tax purposes and therefore no tax expense was recorded for the historical periods prior to the year ended December 31, 2014. OVR was a newly created entity formed in December 2012 that was initially capitalized through the contribution of producing properties, acreage and working capital as well as cash commitments from investors. Upon initial capitalization, the contributed properties, acreage and working capital resulted in one owner retaining a controlling interest in OVR, and despite a change in management, GAAP required OVR to the record the contributed properties at their historical cost basis even though such cost basis was in excess of the valuation agreed upon by members at the time of capitalization. The GAAP requirement resulted in reporting higher DD&A provisions and significant impairments, both in 2013 and 2012, than would have been reported otherwise had the properties been recorded at the agreed upon valuation which approximated fair value.

(In thousands, except per share and production amounts)	Years ended December 31,				
Summary of Operating Data	**2014**	**2013**	**2012**	**2011**	**2010**
Production					
Oil (MBbl)	403	163	90	69	82
Natural gas (MMcf)	2,132	2,635	2,298	2,864	4,306
Natural gas liquids (MBbl)	124	134	76	37	16
Barrel of oil equivalent (MBOE)*	882	737	549	583	816
Average realized prices:					
Oil (per Bbl)	$ 86.29	$ 98.32	$ 96.00	$ 94.88	$ 76.07
Natural gas (per Mcf)	$ 4.39	$ 3.69	$ 2.64	$ 4.21	$ 4.30
Natural gas liquids (per Bbl)	$ 28.29	$ 28.88	$ 31.00	$ 44.20	$ 21.55
Summary of Operations:					
Total revenues	$ 47,994	$ 29,943	$ 22,295	$ 15,470	$ 24,858
Lease operating and workover expenses	$ 10,830	$ 8,768	$ 6,781	$ 8,177	$ 10,150
Severance taxes	$ 2,002	$ 1,225	$ 608	$ 835	$ 1,184
Depreciation, depletion and amortization	$ 18,414	$ 17,111	$ 12,191	$ 16,236	$ 15,623
Pretax loss	$ (6,729)	$ (19,875)	$ (53,321)	$ (46,791)	$ (29,640)
Income tax expense	$ 22,105	$ -	$ -	$ —	$ —
Net loss	$ (28,834)	$ (19,875)	$ (53,321)	$ (46,791)	$ (29,640)
Net loss per share:**					
Basic	$ (3.11)	$ (2.18)	$ (5.84)	$ (5.13)	$ (3.25)
Diluted	$ (3.11)	$ (2.18)	$ (5.84)	$ (5.13)	$ (3.25)
Summary Balance Sheet Data at Year End:					
Net oil and natural gas properties	$ 295,877	$ 147,297	$ 63,462	$ 93,860	$ 129,993
Total assets	$ 451,388	$ 189,858	$ 87,542	$ 104,904	$ 137,513
Long-term debt	$ 11,191	$ 10,825	$ 10,825	$ 5,192	$ 6,500
Total equity	$ 316,528	$ 148,922	$ 61,267	$ 90,985	$ 124,510
Adjusted EBITDAX :***					
Net loss	$ (28,834)	$ (19,875)	$ (53,321)	$ (46,791)	$ (29,640)
Loss (gain) on sale of property and equipment	—	121	(4,785)	5,356	254
Interest expense, net	597	487	273	226	267
Income tax expense	22,105	—	—	—	—
Depreciation, depletion, amortization and accretion	18,731	17,328	12,370	16,410	15,709
Impairment expense	19,359	12,298	52,475	34,294	17,504
Exploration expense	111	2,490	57	11	5,942
Unrealized (gain) loss on derivative contracts	(3,614)	45	—	—	—
Adjusted EBITDAX	**$ 28,455**	**$ 12,894**	**$ 7,069**	**$ 9,506**	**$ 10,036**

* 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).

** For periods prior to the reverse acquisition earnings per share is calculated based on 9,124,452 shares which is the number of shares issued to OVR on December 19, 2014 as a result of the transaction.

** Adjusted EBITDAX is a Non-GAAP measure that differs from the GAAP measure of Net Income. Adjusted EBITDAX is calculated as shown above. Adjusted EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles, but provides additional information for evaluation of our operating performance.

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

The following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements, which are included in the report in Item 8, and the information set forth in Risk Factors under Item 1A. Unless the context otherwise requires, the terms "the Company", "our", "we" "us", and "Earthstone" refer to Earthstone Energy, Inc. and its consolidated subsidiaries.

Overview

We are an independent oil and gas company engaged in the acquisition, development, exploration and production ofonshore, oil and natural gas reserves. As further discussed in this report, future growth in assets, earnings, cash flows and share values will be dependent upon our ability to acquire, discover and develop commercial quantities of oil and natural gas reserves that can be produced at a profit, and assemble an oil and natural gas reserve base with a market value exceeding its acquisition, development and production costs.

Our strategy includes a combination of acquisition, development and exploration activities. Historically, we have shifted our emphasis among these basic activities to take advantage of changing market conditions and to facilitate profitable growth. The majority of our efforts are currently focused on developing our acreage positions in the Eagle Ford trend of Texas and in the Williston Basin of North Dakota and Montana. In addition, it is essential that, over time, our personnel expand our current projects and/or generate additional projects so that we have the potential to economically replace our production and increase our proved reserves. Following is a brief outline of our current plans:

- continue the development of our acreage positions in the Eagle Ford trend ofTexas and in the Williston Basin of North Dakota and Montana;
- maintain and expand our acreage positions and drilling inventory;
- generate additional exploration and development projects;
- pursue attractive corporate acquisitions or mergers and asset acquisitions; and
- obtain additional capital, as needed, through the issuance of equity and/or debt securities.

While the impact and success of our corporate plans cannot be predicted with accuracy, our goal is to replace production and further increase our reserve base at an acquisition or finding cost that will yield attractive rates of return.

On December 19, 2014, we acquired three operating subsidiaries of Oak Valley Resources, LLC, a privately-held Delaware limited liability company ("OVR"), in exchange for shares of our common stock (the "Exchange"), which resulted in a change of control. Pursuant to the Exchange Agreement, OVR contributed to us the membership interests of its three subsidiaries, Oak Valley Operating, LLC ("OVO"), EF Non-Op, LLC ("EF Non-Op") and Sabine River Energy, LLC ("Sabine"), each a Texas limited liability company (collectively "Oak Valley"), in exchange for approximately 9.124 million shares, representing 84% of our common stock. The Exchange has been accounted for as a reverse acquisition in which Oak Valley is considered the acquirer for accounting purposes. All historical financial information contained in this report is that of OVR and its subsidiaries.

Immediately following the Exchange, we acquired an additional 20% undivided ownership interest in certain oil and natural gas properties located in Fayette and Gonzales Counties, Texas, (the "2014 Eagle Ford Acquisition Properties") in exchange for the issuance of approximately 2.957 million shares of our common stock (the "Contribution Agreement") to Flatonia Energy, LLC ("Flatonia"), increasing our ownership in these properties from a 30% undivided ownership to a 50% undivided ownership interest. As a result of the share issuance to Flatonia, OVR's ownership in us decreased from 84% to 66%.

As of December 31, 2014, we had an estimated 22,192 MBOE of proved reserves, consisting of 13,803 MBbls of oil, 38,579 MMcf of natural gas, and 1,959 MBbls of natural gas liquids. Approximately 44% of our proved reserves were classified as proved developed. Production for the year ended December 31, 2014, totaled 882 MBOE, or 2,416 BOE per day, of which 46% was oil.

Results of Operations

Year ended December 31, 2014, compared to the year ended December 31, 2013

Sales and Other Operating Revenues

The quantities of oil, natural gas, and natural gas liquids produced and sold for the years ended December 31, 2014 and 2013, and the average sales price per unit sold are presented below:

	Years Ended December 31,	
	2014	2013
Sales volumes:		
Oil (MBbl)	403	163
Natural gas (MMcf)	2,132	2,635
Natural gas liquids (MBbl)	124	134
Barrel of oil equivalent (MBOE) (1)	882	737
Average prices realized:		
Oil (MBbl)	$ 86.29	$ 98.32
Natural gas (MMcf)	$ 4.39	$ 3.69
Natural gas liquids (MBbl)	$ 28.29	$ 28.88

(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). This ratio does not assume price equivalency and, given price differentials, the price per barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Our revenues for the years ended December 31, 2014 and 2013, are summarized in the table below:

(In thousands)	Years Ended December 31, 2014	2013	Change
Oil, natural gas, and natural gas liquids revenues:			
Oil	$ 34,734	$ 16,038	$ 18,696
Natural gas	$ 9,367	$ 9,714	$ (347)
Natural gas liquids	$ 3,510	$ 3,882	$ (372)
Other operating revenues:			
Gathering income	$ 383	$ 430	$ (47)
Loss on sale of oil and gas properties	$ —	$ (121)	$ 121

Sale of Oil

For the year ended December 31, 2014, oil revenues increased by $18.7 million or 117% relative to the comparable period in 2013. Of the increase, $23.5 million was attributable to increased volume, which was offset by $4.8 million attributable to a decrease in our realized price. Oil sales volumes increased by 240 MBbls primarily due to an increase of 223 MBbls produced from our operated Eagle Ford property. The interest in these properties that we acquired during 2013 provided for 212 MBbls of the increase while the additional interest we acquired during mid-December 2014, the 2014 Eagle Ford Acquisition Properties, provided for an additional 10 MBbls. Also contributing to the increase in oil sales volumes was 6 MBbls from the legacy Earthstone assets and 12 MBbls from our Grayson County wells that were drilled in late 2013. Average realized price per Bbl decreased from $98.32 for the year ended December 31, 2013 to $86.29 for the year ended December 31, 2014.

Sale of Natural Gas

For the year ended December 31, 2014, natural gas revenues decreased by $0.3 million or 4% relative to the comparable period in 2013. Of the decrease, $1.8 million was attributable to decreased volume, which was offset by $1.5 million attributable to an increase in our realized price. Natural gas sales volumes decreased by 503 MMcf primarily due to a decline in production of 406 MMcf from our non-operated Eagle Ford properties in La Salle County, Texas, a decline in production of 143 MMcf from our non-operated east Texas properties, as well as approximately 61 MMcf due to natural production declines in our other properties. The decreases in production volumes were offset by a production increase of 97 MMcf from our operated Eagle Ford property. The interest in these properties that we acquired during 2013 provided for 93 MMcf of the increase while the additional interest we acquired during mid-December 2014, the 2014 Eagle Ford Acquisition Properties, provided for an additional 4 MMcf. Also offsetting the decreases above was 10 MMcf from the legacy Earthstone properties. Our average realized price per Mcf increased from $3.69 for the year ended December 31, 2013 to $4.39 for the year ended December 31, 2014.

Sale of Natural Gas Liquids

For the year ended December 31, 2014, natural gas liquids revenues decreased by $0.4 million or 10% relative to the comparable period in 2013. Of the decrease, $0.3 million was attributable to decreased volume and $0.1 million was attributable to realized price. Natural gas liquids sales volumes decreased by 10 MBbls primarily due to a decline in production of 39 MBbls from our non-operated Eagle Ford properties in La Salle County, Texas, which was offset by increases in production of 26 MBbls from our operated Eagle Ford property. The interest in these properties that was acquired during 2013 accounted for substantially all of this increase. Average realized price per Bbl decreased from $28.88 for the year ended December 31, 2013 to $28.29 for the year ended December 31, 2014.

Production Costs

Our production costs for the years ended December 31, 2014 and 2013 are summarized in the table below:

	Years Ended December 31,		
(In thousands)	2014	2013	Change
Lease operating expenses	$ 10,122	$ 8,426	$ 1,696
Severance taxes	$ 2,002	$ 1,225	$ 777
Re-engineering and workover expenses	$ 708	$ 342	$ 366
LOE per BOE*	$ 10.59	$ 10.47	$ 0.12
Severance tax as a percent of crude oil, natural gas and natural gas liquids revenues	4.20%	4.13%	0.07%

* Excludes ad valorem tax and accretion expense related to the asset retirement obligation.

Lease Operating Expenses

Lease operating expenses ("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, equipment rentals, materials and supplies, fuel and chemicals, LOE includes product marketing and transportation fees, insurance, ad valorem taxes, accretion expense related to asset retirement obligations, and overhead charges provided for in operating agreements. Ad valorem taxes included in LOE were $0.5 million in both the years ended December 31, 2014 and 2013.

LOE increased by $1.7 million or 20% for the year ended December 31, 2014 relative to the comparable period in 2013. The increase in LOE was primarily due to our operated Eagle Ford properties. On a unit-of-production basis, LOE, excluding ad valorem taxes and accretion expense, has remained relatively consistent, increasing by only $0.12 per BOE from $10.59 in 2014 to $10.47 in 2013. The additional interests that we acquired in our operated Eagle Ford property during December 2014 accounted for $50,000 of the total increase while the legacy Earthstone assets accounted for $53,000 of the increase.

Severance Taxes

Severance taxes increased by $0.8 million or 63% for the year ended December 31, 2014 relative to the comparable period in 2013. The increase in severance taxes was primarily due to increased production from our operated Eagle Ford property. The interest in this property that we acquired during 2013 accounted for $0.9 million of the total increase while the additional interest we acquired in December-2014 added $30,000. The legacy Earthstone assets added an additional $35,000. These increases were offset by decreases on our non-operated Eagle Ford property. As a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes increased from 4.13% to 4.20%.

Re-engineering and Workovers

Re-engineering and workover expenses include the costs to restore or enhance production in current producing zones as well as costs of significant non-recurring operations. These costs increased $0.4 million or 107% for the year ended December 31, 2014 relative to the comparable period in 2013. During 2014, we began completing several projects associated with integrating the interests we acquired during 2013 in our operated Eagle Ford property into our operations and reducing the rate at which those wells decline.

General and Administrative Expenses

General and administrative expenses ("G&A"), primarily consist of overhead expenses, employee remuneration, and professional and consulting fees.

G&A expenses increased by $0.1 million from $7.8 million to $7.9 million for the year ended December 31, 2014 relative to the comparable period in 2013. The increase was due to increased headcount and strategic combination related costs but was largely offset by increased overhead cost re-imbursements provided for in our joint operating agreements on the properties we operate.

Depreciation, Depletion and Amortization and Impairment Expense

	Years Ended December 31,		
(In thousands)	**2014**	**2013**	**Change**
DD&A	$ 18,414	$ 17,111	$ 1,303
Impairment expense	$ 19,359	$ 12,298	$ 7,061
DD&A per BOE	$ 20.88	$ 23.22	$ (2.34)

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") increased in 2014 by $1.3 million, or 8% compared to 2013, due to property additions related primarily to drilling and completion expenditures and increased production during the year ended December 31, 2014, as compared to the same period in 2013. However, on a unit-of-production basis, DD&A decreased to $20.88 per BOE during 2014 from $23.22 per BOE during 2013. Despite an increase in capitalized property costs, DD&A on a per BOE basis decreased. Reserves in our operated Eagle Ford properties increased significantly, which helped to bring the per BOE rate down, due to successful drilling in the area which resulted in additional proved reserves. We were also able to decrease the rate per BOE due to improved drilling and completion efficiencies and resultant improvement on finding and development costs on a per BOE basis. The additional interest we acquired in our operated Eagle Ford properties during December 2014 and the legacy Earthstone assets increased DD&A by $0.1 million and $0.1 million, respectively.

Impairment

During the year ended December 31, 2014, we incurred impairment charges of $19.4 million, which consisted of $2.5 million on unproved properties and $16.9 million on proved properties. The impaired unproved properties consisted of acreage throughout Milam County, Texas. The impairment on proved properties primarily resulted from capitalized costs in excess of the fair market value for Oak Valley's non-operated Eagle Ford property and its Grayson County property.

During the year ended December 31, 2013, we incurred impairment charges of $12.3 million which consisted of $2.5 million on unproved properties and $9.8 million on proved properties. The impaired unproved properties primarily consisted of acreage throughout Oklahoma and in Milam County, Texas. The impairment on proved properties resulted from capitalized costs in excess of the fair market value of our non-operated Eagle Ford property, our Milam County property and one of our east Texas properties.

Interest Expense

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Debt outstanding as of December 31, 2014 and December 31, 2013 was $11.2 million and $10.8 million, respectively. Interest expense increased from $0.5 million for the year ended December 31, 2013 to $0.6 million for the year ended December 31, 2014. The $0.1 million increase in interest expense was due to higher amortization of deferred financing costs and increased fees due to a larger credit facility and the accompanying larger unused commitment fees incurred during 2014 versus 2013.

Income Tax Expense

As a result of the Exchange, all historical financial information contained in this report is that of OVR and its subsidiaries. OVR is a partnership for federal income tax purposes and is not subject to federal income taxes or state or local income taxes that follow the federal treatment, and therefore OVR does not pay or accrue for such taxes. Pursuant to the Exchange, Oak Valley has become a subsidiary of Earthstone, a taxable entity; as such we recorded tax expense during the year ended December 31, 2014.

Net Gain on Derivative Contracts

During the year ended December 31, 2014, the Company recorded a net gain on derivative contracts of $4.4 million, consisting of net realized gains on settlements of $0.8 million and unrealized mark-to-market gains of $3.6 million. During the year ended December

31, 2013, the Company recorded a net gain on derivative contracts of $0.3 million, consisting of net realized gains on settlements of $0.3 million and unrealized mark-to-market losses of $45,000.

Year ended December 31, 2013 compared to the year ended December 31, 2012

Sales and Other Operating Revenues

The quantities of oil, natural gas, and natural gas liquids produced and sold for the years ended December 31, 2013 and 2012, and the average sales price per unit sold are presented below:

	Years Ended December 31,			
	2013		2012	
Sales volumes:				
Oil (MBbl)		163		90
Natural gas (MMcf)		2,635		2,298
Natural gas liquids (MBbl)		134		76
Barrel of oil equivalent (MBOE) (1)		737		549
Average prices realized:				
Oil (MBbl)	$	98.32	$	96.00
Natural gas (MMcf)	$	3.69	$	2.64
Natural gas liquids (MBbl)	$	28.88	$	31.00

(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). This ratio does not assume price equivalency and, given price differentials, the price per barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Our revenues for the years ended December 31, 2013 and 2012 are summarized in the table below:

	Years Ended December 31,					
(In thousands)	2013		2012		Change	
Oil, natural gas, and natural gas liquids revenues:						
Oil	$	16,038	$	8,679	$	7,359
Natural gas	$	9,714	$	6,064	$	3,650
Natural gas liquids	$	3,882	$	2,348	$	1,534
Other operating revenues:						
Gathering income	$	430	$	419	$	11
(Loss) gain on sale of oil and gas properties	$	(121)	$	4,785	$	(4,906)

Sale of Oil

For the year ended December 31, 2013, crude oil revenues increased by $7.4 million 85% relative to the comparable period in 2012. Of the increase, $7.0 million was due to volume and $0.4 million was attributable to realized price. Crude oil sales volumes increased by 73 MBbls, consisting of 90 MBbls produced from our operated Eagle Ford property that was acquired in the second half of 2013, which was offset by natural production declines in other properties. Our average realized price per Bbl increased from $96.00 for the year ended December 31, 2012 to $98.32 for the year ended December 31, 2013.

Sale of Natural Gas

For the year ended December 31, 2013, natural gas revenues increased by $3.7 million or 60% relative to the comparable period in 2012. Of the increase, $0.9 million was due to volume and $2.8 million was attributable to realized price. Natural gas sales volumes increased by 337 MMcf, consisting of 31 MMcf produced from our operated Eagle Ford property that was acquired in the second half of 2013 and 600 MMcf produced from new non-operated Eagle Ford wells that were drilled and completed in La Salle County, Texas, which was offset by a decrease in production of 294 MMcf from other properties. Our average realized price per Mcf increased from $2.64 for the year ended December 31, 2012 to $3.69 for the year ended December 31, 2013.

Sale of Natural Gas Liquids

For the year ended December 31, 2013, natural gas liquids revenues increased $1.5 million or 65% relative to the comparable period in 2012. Of the increase, $1.8 million was due to volume, which was offset by $0.3 million attributable to a decrease in realized price.

Natural gas liquids sales volumes increased by 58 MBbls, consisting primarily of 49 MBbls produced from our new non-operated Eagle Ford wells that were drilled and completed in La Salle County, Texas. Our average realized price per Bbl decreased from $31.00 for the year ended December 31, 2012 to $28.88 for the year ended December 31, 2013.

Production Costs

Our production costs for the years ended December 31, 2013 and 2012, are summarized in the table below:

	Years Ended December 31,		
(In thousands)	2013	2012	Change
Lease operating expenses	$ 8,426	$ 6,211	$ 2,215
Severance taxes	$ 1,225	$ 608	$ 617
Re-engineering and workover expenses	$ 342	$ 570	$ (228)
LOE per BOE*	$ 10.47	$ 10.49	$ (0.02)
Severance tax as a percent of crude oil, natural gas and natural gas liquids revenues	4.13%	3.56%	0.57%

* Excludes ad valorem tax and accretion expense related to the asset retirement obligation

Lease operating expenses ("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, equipment rentals, materials and supplies, fuel and chemicals, LOE includes product marketing and transportation fees, insurance, ad valorem taxes, accretion expense related to asset retirement obligations, and overhead charges provided for in operating agreements. Ad valorem taxes included in LOE for the years ended December 31, 2013 and 2012 were $0.5 million and $0.3 million, respectively.

LOE increased by $2.2 million or 36% for the year ended December 31, 2013 relative to the comparable period in 2012. The increase in LOE was primarily due to our operated Eagle Ford Asset property that was acquired during 2013. On a unit-of-production basis, LOE, excluding ad valorem taxes and accretion expense, has remained relatively consistent, decreasing by $0.02 per BOE from $10.49 in 2012 to $10.47 in 2013. Ad valorem taxes in 2013 increased relative to the comparable period in 2012 by $0.2 million due to higher assessed property values.

Severance Taxes

Severance taxes increased by $0.6 million or 101% to $1.2 million for the year ended December 31, 2013 relative to the comparable period in 2012. The increase in severance taxes was primarily due to production from our operated Eagle Ford property that was acquired in the second half of 2013. As a percentage of revenues from oil, natural gas, and natural gas liquids, severance taxes increased from 3.6% to 4.1%. This increase was attributable to our operated Eagle Ford property, which added a significant amount of production from wells that produce primarily oil and are not subject to tax exemptions, whereas in 2012, a significant amount of new production was from high-cost gas wells that qualify for full or partial severance tax exemptions.

Re-engineering and Workovers

Re-engineering and workover expenses include the costs to restore or enhance production in current producing zones as well as costs of significant non-recurring operations. Re-engineering and workover expenses decreased from approximately $0.6 million to $0.3 million during the twelve months ended December 31, 2013 relative to the comparable period in 2012. During 2013, we devoted less capital to re-engineering and workover projects and more effort towards integrating our operated our Eagle Ford property that was acquired during 2013 into our operations and developing an appropriate drilling program.

General and Administrative Expenses

General and administrative expenses ("G&A"), primarily consist of overhead expenses, employee remuneration, and professional and consulting fees. G&A expenses increased by $4.5 million from approximately $3.3 million to $7.8 million for the year ended December 31, 2013 relative to the comparable period in 2012. The increase was due to greater headcount and other administrative expenses related to the December 2012 formation and capitalization of OVR. In addition, we recorded $1.0 million of professional fees and other costs associated with the purchase of our operated Eagle Ford property in 2013.

Depreciation, Depletion and Amortization and Impairment Expense

OVR was capitalized on December 21, 2012, and acquired certain subsidiaries in exchange for equity as part of a larger transaction. In accordance with GAAP, this transaction was treated as a common control transaction. As such, OVR was required to report the historical results of operations and financial position for the consolidated subsidiaries and retain the historical cost basis for their assets even though such historical cost bases were in excess of the valuation agreed upon by members at the time of capitalization. This GAAP requirement resulted in the reporting of higher DD&A provisions and significant impairments, both in 2013 and 2012, than would have been reported otherwise had the properties been recorded at the agreed upon valuation or fair value. As of December 31, 2013, the net book value had been reduced to less than the equity valuation through DD&A expense and impairments calculated in accordance with GAAP.

	Years Ended December 31,		
(In thousands)	**2013**	**2012**	**Change**
DD&A	$ 17,111	$ 12,191	$ 4,920
Impairment expense	$ 12,298	$ 52,475	$ (40,177)
DD&A per BOE	$ 23.22	$ 22.20	$ 1.02

DD&A in for the year ended December 31, 2013 increased by $4.9 million, or 40%, compared to the year ended December 31, 2012 due to higher capitalized property costs and increased production during the year ended December 31, 2013 relative to the comparable period in 2012. Capitalized property costs increased due to (i) the addition of our operated Eagle Ford properties during the second half of 2013; (ii) costs incurred related to the Eagle Ford drilling program; and (iii) drilling activity on our non-operated Eagle Ford property. On a unit-of-production basis, DD&A increased from $22.20 per BOE during 2012 to $23.22 per BOE during 2013.

Impairment

During the year ended December 31, 2013, we incurred impairment charges of $12.3 million, which consisted of $2.5 million on unproved properties and $9.8 million on proved properties. The impaired unproved properties primarily consisted of acreage throughout Oklahoma and in Milam County, Texas. The impairment on proved properties resulted from capitalized costs in excess of the fair market value our non-operated Eagle Ford property, our Milam County property and one of our east Texas properties.

During 2012, we had impairment charges of approximately $52.5 million which consisted of $8.6 million on unproved properties and $43.9 million on proved properties. The impairments on the unproved properties resulted primarily from leases that expired on acreage or acreage that had a cost basis in excess of its fair value in Madison, Zapata and Caldwell Counties in Texas. The proved property impairments primarily resulted from capitalized drilling, leasehold, and tangible equipment costs that were in excess of the fair market value on our non-operated east Texas property and the Red Oak Norris field in Oklahoma.

Interest expense includes commitment fees, amortization of deferred financing costs, and interest on outstanding indebtedness. Debt outstanding as of December 31, 2013 and 2012 was $10.8 million. Interest expense increased from $0.3 million for the year ended December 31, 2012 to $0.5 million for the year ended December 31, 2013. The $0.2 million increase in interest expense is due to borrowings during 2012 that remained outstanding throughout 2013, higher commitment fees for the second half of 2013 as a result of a larger unused borrowing base during the second half of 2013 as well as higher amortization of deferred financing costs.

Income Tax Expense

As a result of the Exchange, all historical financial information contained in this report is that of OVR. OVRis a partnership for federal tax purposes and is not subject to federal income taxes or state or local income taxes that follow the federal treatment, and therefore did not pay or accrue for such taxes.

Net Gain on Derivative Contracts

During the year ended December 31, 2013, we recorded a net gain on derivative contracts of $0.3 million, consisting of net realized settlement gains of $0.3 million and unrealized mark-to-market losses of $45,000. We were was not a party to any derivative contracts during the year ended December 31, 2012. Therefore, there was no net gain (loss) on derivative contracts recorded during 2012.

Liquidity and Capital Resources

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, borrowings under our credit facility, sale of non-strategic assets, various means of corporate and project financing, and the issuance of additional debt and/or equity securities. In addition, we may continue to partially finance our drilling activities through the sale of participations to industry partners or financial institutions, and we could structure such arrangements on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate capital costs.

Financing activities for the years ended December 31, 2014, 2013, and 2012 provided $106.9 million, $107.5 and $24.8 in equity contributions, respectively. For the year ended December 31, 2012, we distributed $1.2 million of members' capital to its former managers pursuant to severance agreements. For the year ended December 31, 2014 and 2012, financing activities resulted in a net increase in debt of $0.4 million and $5.6 million, respectively.

Senior Secured Revolving Credit Facility

In connection with the closing of the Exchange Agreement and the Contribution Agreement, on December 19, 2014, we entered into a credit agreement providing for a $500.0 million four-year senior secured revolving credit facility (the "Credit Agreement") with BOKF, NA dba Bank of Texas ("Bank of Texas"), as agent and lead arranger, Wells Fargo Bank, National Association ("Wells Fargo"), as syndication agent, and the Lenders signatory thereto (collectively with Bank of Texas and Wells Fargo, the "Lender").

The initial borrowing base of the Credit Agreement is $80.0 million and is subject to redetermination on the first business day of May and November of each year. The amounts borrowed under the Credit Agreement bear annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus the applicable utilization margin of 1.50% to 2.50% or (b) the base rate plus the applicable utilization margin of 0.50% to 1.50%. Principal amounts outstanding under the Credit Agreement are due and payable in full at maturity on December 19, 2018. All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of our assets. Additional payments due under the Credit Agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate ranges from 0.375% to 0.50% per year, depending upon the unutilized portion of the borrowing base in effect from time to time. We are also required to pay customary letter of credit fees. At December 31, 2014, we had approximately $69.0 million borrowing capacity under our Credit Agreement. Our Credit Agreement contains customary covenants. As of December 31, 2014, we were in compliance with our debt covenants. For additional details, see "Note 8 – Long-Term Debt" within the Notes to the Consolidated Financial Statements included in Part II, Item 8. Financial Statements and Supplementary Data.

Cash Flows from Operating Activities

For the years ended December 31, 2014, 2013, and 2012, net cash provided by operating activities was $75.8 million, $15.3 million, and $15.0 million respectively. The year-over-year increases in operating cash flows were directly attributable to increased production and higher realized prices. The increased production came in large part from our operated Eagle Ford property. We believe that we have sufficient liquidity and capital resources to execute our business plan over the next 12 months and for the foreseeable future. We expect to primarily fund our planned capital program through a combination of available working capital, cash flows from operating activities, borrowings under our Credit Agreement, and the issuance of additional debt and/or equity securities.

We had significant net cash provided by operating activities for the years ended December 31, 2014, 2013 and 2012 while we recorded net losses during those same years. The net loss for the year ended December 31, 2014 was $28.8 million due to non-cash items that decreased our operating and net income. During the year ended December 31, 2014 we recorded impairments of $19.4 million, DD&A of $18.4 million and deferred income tax expense of $22.1 million. We also had changes in working capital items that increased our operating cash flows by $47.9 million. The net loss for the year ended December 31, 2013 was $19.9 million due to non-cash items that decreased our operating and net income. During the year ended December 31, 2013 we recorded impairments of $12.3 million and DD&A of $17.1 million. We also had changes in working capital items that increased our operating cash flows by $3.2 million. The net loss for the year ended December 31, 2012 was $53.3 million due to non-cash items that decreased our operating and net income. During the year ended December 31, 2013 we recorded impairments of $52.5 million and DD&A of $12.2 million. We also had changes in working capital items that increased our operating cash flows by $8.1 million.

Cash Flows from Investing Activities

Cash applied to oil and natural gas properties for the years ended December 31, 2014, 2013, and 2012 was $83.0 million, $31.1 million and $39.4 million, respectively. During 2014, we used $18.8 million in addition to the common stock issued in connection with the Contribution Agreement to acquire an additional 20% undivided ownership interest in our operated Eagle Ford property. During 2013, we also used $86.7 million to fund the original acquisition of our operated Eagle Ford property. Cash applied to other non-oil and gas property fixed assets for the years ended December 31, 2014, 2013, and 2012 was $1.4 million, $0.7 million and $0.1 million, respectively. In 2013, we received $0.9 million of insurance proceeds from a well control issue on our non-operated Eagle Ford property in La Salle County, Texas. For the years ended December 31, 2013 and 2012, we received proceeds from the sale of oil and gas properties of $0.5 million and $10.0 million, respectively.

Hedging Activities

Hedging commodity prices for a portion of our production is a fundamental part of our financial management strategy. We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of its production. In implementing our hedging strategy, we seek to effectively manage cash flow to minimize price volatility.

We seek to reduce our sensitivity to oil and natural gas price volatility and secure favorable debt financing terms by entering into commodity derivative transactions. We believe our hedging strategy should result in greater predictability of internally generated funds, which in turn can be dedicated to capital development projects and corporate obligations.

Current Commodity Derivative Contracts

The following is a summary of our current oil and natural gas commodity derivative contracts as of December 31, 2014:

Period	Instrument	Commodity	Volume in MMBtu / Bbls	Fixed Price
January 2015 - March 2015	Swap	Natural Gas	150,000	$ 4.175
January 2015 - March 2015	Swap	Natural Gas	75,000	$ 4.30
January 2015 - June 2015	Swap	Crude Oil	21,000	$ 91.50
January 2015 - December 2015	Swap	Crude Oil	66,000	$ 95.10

In March 2015, we entered into an additional oil swap. The swap has a term from April 2015 through March 2016, and provides for 5,000 barrels per month at a fixed price of $57.00 per barrel.

Fair Market Value of Commodity Derivatives

	December 31, 2014		December 31, 2013	
(In thousands)	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Assets:				
Current	$ 3,293	$ 276	$ 154	$ —
Non-current	$ —	$ —	$ —	$ —
Liabilities:				
Current	$ —	$ —	$ (105)	$ (67)
Non-current	$ —	$ —	$ —	$ (28)

Assets and liabilities are netted within each commodity and counterparty on the balance sheet. For the balances without netting, refer to “Note 4 – *Derivative Financial Instruments*” in the Notes To Consolidated Financial Statements contained in this report.

At December 31, 2014, a 10% increase in per unit commodity prices would cause the total fair value asset of our commodity derivative financial instruments to decrease by $0.6 million to $3.0 million. A 10% decrease in per unit commodity prices would cause the total fair value asset of our commodity derivative financial instruments to increase by $0.5 million to $4.1 million. There would also be a similar increase or decrease in “Net gain on derivative contracts” on the Consolidated Statement of Operations.

Commitments and Contingencies

We had the following contractual obligations and commitments as of December 31, 2014:

(In thousands)	2015	2016	2017	2018	2019	Thereafter
Debt	$ -	$ -	$ -	$ 11,191	$ -	$ -
Drilling contracts	8,682	8,845	-	-	-	-
Gas contract*	1,643	1,647	1,643	1,643	1,643	2,327
Office leases	715	639	609	619	575	-
Asset retirement obligations	408	94	2,350	143	394	2,689
Total	$ 11,448	$ 11,225	$ 4,602	$ 13,596	$ 2,612	$ 5,016

* We have reserved gathering and processing capacity in a pipeline and have a volume commitment whereby we pay the owner of the pipeline a fee of $0.45 per MMBtu to hold 10,000 MMBtu per day of capacity. The rate and terms under this purchasing and processing contract expire on June 1, 2021.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

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, 2014. 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 periodically enter into commodity derivative contracts to manage our exposure to crude oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flows to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based, in part, on our view of current and future market conditions. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge, and the counterparties’ creditworthiness. All our counterparties are participants in our credit facility.

All derivative instruments are recorded on the Consolidated Balance Sheets as an asset or a liability. Our swaps are valued based on a discounted future cash flow model. Our primary input for the model is the NYMEX futures index. Our model is validated by the counterparty’s marked-to-market statements. The discount rate used in determining the fair values of these instruments includes a measure of nonperformance risk. Changes in the fair values of our commodity derivative instruments are included in “*Net gain on derivative contracts*” on the Consolidated Statements of Operations.

Income Taxes and Uncertain Tax Positions

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

We will consider a tax position settled if the taxing authority has completed its examination, we do not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. We use the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, then we will not record the tax benefit. The amount of interest expense that we recognize related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil, natural gas, and natural gas liquids. Revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has been transferred, and collectability is probable. 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 ASC, *Intangibles – Goodwill and Other* ("ASC 350"). 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 350 requires that intangible assets with indefinite lives, including 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 follow FASB Accounting Standards Update (ASU) No. 2011-08, *Testing for Goodwill Impairment* ("ASU 2011-08"). ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the entity is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test.

Recently Issued Accounting Standards

In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers. The objective of this guidance is to establish principles for reporting information about the nature, timing, and uncertainty of revenue and cash flows arising from an entity's contracts with customers, including qualitative and quantitative disclosures around contracts with customers, significant judgments and change in judgments, and assets recognized from the costs to obtain or fulfill a contract. The standards update is effective for interim and annual periods beginning after December 15, 2016. We will adopt this standards update, as required, beginning with the first quarter of 2017. We are in the process of evaluating the impact, if any, of this guidance on its consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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 acquired and liabilities assumed 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 acquired and liabilities assumed involves the use of judgment, since some of the assets acquired and liabilities assumed 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 comparisons 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.

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 Disclosures

As previously reported on our Current Report on Form 8-K filed with the SEC on December 29, 2014 (the “prior 8-K”), on December 19, 2014, we dismissed our former independent registered public accounting firm and appointed Weaver and Tidwell, L.L.P. as our independent registered public accounting firm. For more information, please refer to the prior 8-K.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act, the phrase “disclosure controls and procedures” means controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2014. This evaluation was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Accounting Officer. Based on this evaluation, our Chief Executive Officer and Chief Accounting Officer concluded that, as of December 31, 2014, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;

(ii) 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 are being made only in accordance with authorizations of our management and directors; and

(iii) 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.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of our management, including the Chief Executive Officer and Chief Accounting Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control-Integrated Framework*, (2013 Version) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this report. Therefore, this report does not include such an attestation.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executives Officers and Corporate Governance

See list of "Executive Officers of the Company" under Item 1 of this report, which is incorporated herein by reference.

Other information required by this item is incorporated herein by reference to our 2015 Proxy Statement or Form 10-K/A which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 11. Executive Compensation

Information called for by Item 11 of this report will be set forth in our 2015 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

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

See "Equity Compensation Plan Information" under Item 5 of this report, which is incorporated herein by reference for the Company's Securities Authorized for Issuance under Equity Compensation Plans.

Other information required by this item will be set forth in our 2015 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

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

Information called for by Item 13 of this report will be set forth in our 2015 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information called for by Item 14 of this report will be set forth in our 2015 Proxy Statement or Form 10-K/A, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement and Schedules

Form 10-K for the fiscal year ended December 31, 2014.

		Incorporated by Reference					
Exhibit No.	Description	Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1	Amended and Restated Certificate of Incorporation of Earthstone Energy, Inc. dated February 26, 2010.	8-K	001-35049	3(i)	March 3, 2010		
3.1(a)	Certificate of Amendment to Certificate of Incorporation of Earthstone Energy, Inc. dated December 20, 2010.	8-K	001-35049	3(i)	January 4, 2011		
3.1(b)	Certificate of Amendment of Certificate of Incorporation of Earthstone Energy, Inc. dated December 19, 2014.	8-K	001-35049	3.1	December 29, 2014		
3.2	Amended and Restated Bylaws of Earthstone Energy, Inc. dated February 26, 2010.	8-K	001-35049	3(ii)	March 10, 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		
4.1	Rights Agreement dated February 4, 2009 between Earthstone Energy, Inc. and Corporate Stock Transfer, Inc.	8-K	001-35049	4.1	February 5, 2009		
4.1(a)	First Amendment to the Rights Agreement dated May 15, 2014, by and among Earthstone Energy, Inc., Corporate Stock Transfer, Inc., and Direct Transfer LLC.	8-A/A	001-35049	4.1	May 16, 2014		
4.1(b)	Second Amendment to the Rights Agreement dated May 15, 2014 between Earthstone Energy, Inc. and Direct Transfer LLC.	8-A/A	001-35049	4.2	May 16, 2014		
4.1(c)	Third Amendment to the Rights Agreement dated October 16, 2014 between Earthstone Energy, Inc. and Direct Transfer LLC.	8-A/A	001-35049	4.1	October 20, 2014		
4.2	Specimen Common Stock Certificate of Earthstone Energy, Inc.	10-K	001-35049	4.2	June 16, 2011		
10.1	Credit Agreement dated December 19, 2014, by and among Earthstone Energy, Inc., Oak Valley 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.	8-K	001-35049	10.4	December 29, 2014		
10.2	Exchange Agreement dated May 15, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	May 16, 2014		

		Incorporated by Reference					
Exhibit No.	Description	Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.2(a)	Amendment to the Exchange Agreement dated September 26, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	October 2, 2014		
10.3	Contribution Agreement dated October 16, 2014, among Earthstone Energy, Inc., Oak Valley Resources, LLC, Sabine River Energy, LLC, Oak Valley Operating, LLC, Parallel Resource Partners, LLC, and Flatonia Energy, LLC.	8-K	001-35049	10.1	October 20, 2014		
10.4	Registration Rights Agreement dated December 19, 2014 between Earthstone Energy, Inc. and Oak Valley Resources, LLC.	8-K	001-35049	10.1	December 29, 2014		

10.5	Registration Rights Agreement dated December 19, 2014, by and among Earthstone Energy, Inc., Parallel Resource Partners, LLC, Flatonia Energy, LLC, and Oak Valley Resources, LLC.	8-K	001-35049	10.2	December 29, 2014		
10.6†	Earthstone Energy, Inc. Employee Severance Compensation Plan.	8-K	001-35049	10.2	May 16, 2014		
10.7†	Earthstone Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-35049	10.3	December 29, 2014		
10.8	Form of Indemnification Agreement.	8-K	001-35049	10.5	December 29, 2014		
10.9†	Earthstone Energy, Inc. 2011 Equity Incentive Compensation Plan.	Def. Proxy Statement	001-35049	Appendix A	July 29, 2011		
10.10†	Earthstone Energy, Inc. Performance Bonus Plan.	10-K/A	001-35049	10.3	October 9, 2009		
14	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	
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

		Incorporated by Reference					
Exhibit No.	Description	Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
32.2	Certification of the Chief Accounting Officer 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.

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
Title: President and Chief Executive Officer
(Principal Executive Officer)

Date: March 27, 2015

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, President and Chief Executive Officer (Principal Executive Officer)	March 27, 2015
/s/ G. Bret Wonson G. Bret Wonson	Principal Financial Officer and Principal Accounting Officer	March 27, 2015
/s/ Jay F. Joliat Jay F. Joliat	Director	March 27, 2015
/s/ Ray Singleton Ray Singleton	Director	March 27, 2015
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	March 27, 2015
/s/ Brad A. Thielemann Brad A. Thielemann	Director	March 27, 2015
/s/ Zachary G. Urban Zachary G. Urban	Director	March 27, 2015
/s/ Robert L. Zorich Robert L. Zorich	Director	March 27, 2015

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Earthstone Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Earthstone Energy, Inc., and subsidiaries (the Company) (formerly Oak Valley Resources, LLC) as of December 31, 2014 and 2013, and the related consolidated statements of operations, equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the entity's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Earthstone Energy, Inc., and subsidiaries (formerly Oak Valley Resources, LLC) as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

WEAVER AND TIDWELL, L.L.P.
March 27, 2015
Houston, Texas

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

ASSETS	December 31, 2014	December 31, 2013
Current assets:		
Cash and cash equivalents	$ 100,447	$ 25,423
Accounts receivable:		
Oil, natural gas, and natural gas liquids revenues	14,016	8,122
Joint interest billings and other	9,417	7,541
Current derivative assets	3,569	154
Prepaid expenses and other current assets	1,578	122
Total current assets	129,027	41,362
Oil and gas properties, successful efforts method:		
Proved properties	317,006	184,075
Unproved properties	76,791	43,011
Total oil and gas properties	393,797	227,086
Accumulated depreciation, depletion, and amortization	(97,920)	(79,789)
Net oil and gas properties	295,877	147,297
Other noncurrent assets:		
Goodwill	22,992	—
Office and other equipment, less accumulated depreciation of $474 and $191, respectively	2,109	560
Land	101	101
Other noncurrent assets	1,282	538
TOTAL ASSETS	$ 451,388	$ 189,858
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 28,753	$ 7,428
Accrued expenses	20,529	5,768
Revenues and royalties payable	17,364	10,184
Advances	21,398	3,520
Current derivative liabilities	—	172
Asset retirement obligations	408	70
Total current liabilities	88,452	27,142
Noncurrent liabilities:		
Noncurrent derivative liabilities	—	28
Long-term debt	11,191	10,825
Asset retirement obligations	5,670	2,941
Deferred tax liability	29,258	—
Other noncurrent liabilities	289	—
Total noncurrent liabilities	46,408	13,794
Total liabilities	134,860	40,936
Commitments and Contingencies (Note 11)		
Equity:		
Members' equity	—	148,922
Preferred stock, $0.001 par value, 20,000,000 shares authorized; none issued or outstanding	—	—
Common stock, $0.001 par value, 100,000,000 shares authorized; 13,835,128 shares issued and outstanding in 2014 and none in 2013	14	—
Additional paid-in capital	358,086	—
Accumulated deficit	(41,112)	—
Treasury stock, 15,414 shares in 2014 and none in 2013	(460)	—
Total equity	316,528	148,922
TOTAL LIABILITIES AND EQUITY	$ 451,388	$ 189,858

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,		
	2014	2013	2012
REVENUES			
Oil, natural gas, and natural gas liquids revenues:			
Oil	$ 34,734	$ 16,038	$ 8,679
Natural gas	9,367	9,714	6,064
Natural gas liquids	3,510	3,882	2,348
Total oil, natural gas, and natural gas liquids revenues	47,611	29,634	17,091
Gathering income	383	430	419
(Loss) gain on sale of oil and gas properties	—	(121)	4,785
Total revenues	47,994	29,943	22,295
OPERATING COSTS AND EXPENSES			
Production costs:			
Lease operating expense	10,122	8,426	6,211
Severance taxes	2,002	1,225	608
Re-engineering and workovers	708	342	570
Impairment expense	19,359	12,298	52,475
Depreciation, depletion, and amortization	18,414	17,111	12,191
Exploration expense	111	2,490	57
General and administrative expense	7,864	7,751	3,280
Total operating costs and expenses	58,580	49,643	75,392
Loss from operations	**(10,586)**	**(19,700)**	**(53,097)**
OTHER INCOME (EXPENSE)			
Interest expense, net	(597)	(487)	(273)
Net gain on derivative contracts	4,392	296	—
Other income, net	62	16	49
Total other income (expense)	3,857	(175)	(224)
Loss before income taxes	(6,729)	(19,875)	(53,321)
Income tax expense	22,105	—	—
Net loss	**$ (28,834)**	**$ (19,875)**	**$ (53,321)**
Net loss per common share:			
Basic	$ (3.11)	$ (2.18)	$ (5.84)
Diluted	$ (3.11)	$ (2.18)	$ (5.84)
Weighted average common shares outstanding:			
Basic	9,279,324	9,124,452	9,124,452
Diluted	9,279,324	9,124,452	9,124,452

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

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

	Members' Equity	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock Shares	Treasury Stock Amount	Total Equity
At December 31, 2011	$ 90,985							$ 90,985
Contributions from Oak Valley Resources, LLC members	24,790							24,790
Distributions	(1,187)							(1,187)
Net Loss	(53,321)							(53,321)
At December 31, 2012	61,267	—	—	—	—	—	—	61,267
Contributions from Oak Valley Resources, LLC members	107,530							107,530
Net loss	(19,875)							(19,875)
At December 31, 2013	148,922	—	—	—	—	—	—	148,922
Contributions from Oak Valley Resources, LLC members	107,020							107,020
Contribution of Oak Valley Subsidiaries in exchange for shares	(268,220)	9,124,452	9	268,211	—	—	—	—
Reverse acquisition with Oak Valley	—	1,753,388	2	33,453		(15,414)	(460)	32,995
2014 Eagle Ford Acquisition Properties	—	2,957,288	3	56,422	—			56,425
Net income (loss)	12,278	—	—	—	(41,112)	—	—	(28,834)
At December 31, 2014	$ —	13,835,128	$ 14	$ 358,086	$ (41,112)	(15,414)	$ (460)	$ 316,528

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, 2014	2013	2012
Cash flows from operating activities:			
Net loss	$ (28,834)	$ (19,875)	$ (53,321)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, and amortization	18,414	17,111	12,191
Impairment of proved and unproved oil and gas properties	19,359	12,298	52,475
Unrealized (gain) loss on derivative contracts	(3,614)	45	—
Dry hole costs	—	2,096	57
Loss (gain) on sales of oil and gas properties	—	121	(4,785)
Accretion of asset retirement obligations	317	217	179
Deferred income taxes	22,105	—	—
Amortization of deferred financing costs	164	103	48
Settlement of asset retirement obligations	(56)	—	—
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(5,305)	(12,141)	1,202
(Increase) decrease in prepaid expenses and other	(194)	(81)	89
Increase in accounts payable and accrued expenses	28,408	2,171	6,762
Increase in revenue and royalties payable	7,099	9,698	88
Increase in advances	17,925	3,520	—
Net cash provided by operating activities	75,788	15,283	14,985
Cash flows from investing activities:			
Acquisitions of proved and unproved property	(18,772)	(86,687)	—
Additions to oil and gas property and equipment	(83,041)	(31,162)	(39,433)
Additions to other property and equipment	(1,385)	(678)	(97)
Reverse acquisition with Oak Valley, net of cash	(4,239)	—	—
Insurance proceeds	—	923	—
Proceeds from sales of oil and gas properties	—	488	9,976
Net cash used in investing activities	(107,437)	(117,116)	(29,554)
Cash flows from financing activities:			
Issuance of long-term debt	11,191	—	10,825
Reduction of long-term debt	(10,825)	—	(5,192)
Deferred financing costs	(613)	(425)	(20)
Contributions, net of issuance costs	106,920	107,530	24,790
Distributions	—	—	(1,187)
Net cash provided by financing activities	106,673	107,105	29,216
Net increase in cash and cash equivalents	75,024	5,272	14,647
Cash and cash equivalents at beginning of period	25,423	20,151	5,504
Cash and cash equivalents at end of period	$ 100,447	$ 25,423	$ 20,151
Supplemental disclosure of cash flow information			
Cash paid for:			
Interest	$ 493	$ 375	$ 238
Non-cash investing and financing activities:			
Asset retirement obligations	$ 237	$ 1,033	$ 66
Stock issued for 2014 Eagle Ford Acquisition Properties	$ 56,425	$ —	$ —

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 formed in 1969, is a growth-oriented independent oil and gas exploration and production company engaged in the acquisition, development, exploration and production of onshore, unconventional reserves, with a current focus on the Eagle Ford trend of South Texas and in the Williston Basin of North Dakota and Montana. The Company also has conventional wells in East Texas, South Texas, Louisiana and Oklahoma. Unless the context otherwise requires, the terms “Earthstone” and the “Company” refer to Earthstone Energy, Inc. and it consolidated subsidiaries. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Oak Valley Resources, LLC (“OVR”), is a Delaware limited liability company, formed on December 14, 2012. Prior to the Exchange (described below), OVR was an independent energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids (“NGL”), with properties in Texas, Oklahoma, and Louisiana. OVR was formed through a series of transactions that conveyed properties and committed cash contributions from various investors including EnCap Investments L.P. (“EnCap”), Wells Fargo Central Pacific Holdings, Inc. (“Wells Fargo”), VILLCo Capital II, LLC (“VILLco”) and an affiliate of OVR, Oak Valley Management, LLC (“OVM”).

On December 19, 2014, the Company acquired three operating subsidiaries of OVR, in exchange for shares of Earthstone common stock (the “Exchange”), which resulted in a change of control of the Company. Pursuant to the Exchange Agreement, OVR contributed to Earthstone the membership interests of its three subsidiaries, Oak Valley Operating, LLC (“OVO”), EF Non-Op, LLC (“EF Non-Op”) and Sabine River Energy, LLC (“Sabine”), each a Texas limited liability company (collectively “Oak Valley”), in exchange for 9.124 million shares, representing 84% of the Company’s common stock. The transaction has been accounted for as a reverse acquisition whereby Oak Valley is considered the acquirer for accounting purposes. All historical financial information contained in this Annual Report on Form 10-K is that of Oak Valley.

Immediately following the exchange, the Company, through its now wholly owned subsidiary, Sabine, acquired an additional 20% undivided ownership interest in certain crude oil and gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of approximately 2.957 million shares of common stock (the “Contribution Agreement”) to Flatonia Energy, LLC, increasing the Company’s ownership in these properties from a 30% undivided ownership to a 50% undivided ownership interest. As a result of the share issuance to Flatonia, OVR’s ownership in the Company decreased from 84% to 66%.

Note 2. – Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company and its wholly owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States of America. Prior to being capitalized on December 21, 2012, all of the Company’s wholly owned subsidiaries were controlled by EnCap. All of the companies included in the transaction had fiscal years ending December 31. The consolidated financial statements for the period ended December 31, 2012 were prepared by combining all the previously separate subsidiaries in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 805, *Business Combinations* (“ASC Topic 805”). ASC Topic 805 states that if a transaction combines two or more commonly controlled entities that historically have not been presented together, the resulting financial statements for those periods presented require retrospective presentation of the financial statements for all the periods presented, as if the combination had been in effect since the inception of common control.

When accounting for a transfer of assets or exchange of equity interests between entities under common control, the entity that receives the net assets or the equity interests should initially measure the assets and liabilities transferred at their historical carrying amounts. Therefore, the net assets included in the accompanying consolidated financial statements are shown at their historical carrying value.

On December 18, 2012, prior to the assignment of membership interests of Oak Valley Energy, LLC, a Delaware Limited Liability Company (“OVE”), to the Company, one of OVE’s subsidiaries was transferred to a non-affiliated entity. In accordance with ASC Topic 805, the consolidated financial statements include the activities of that subsidiary through the date of transfer. The amount of revenue and net income from the OVE subsidiary included in the Company’s Consolidated Statement of Operations for the year ended December 31, 2012, was $4.2 million and $2.4 million, respectively. Please see Note 3 “*Acquisitions and Divestitures*” for more information on this transfer.

As of December 31, 2014, the Company's wholly-owned subsidiaries included:

- Oak Valley Operating, LLC, a Texas limited liability company formed on May 26, 2011. OVO serves as the operator on all Company-operated properties in Fayette and Gonzales Counties, Texas, Louisiana and Oklahoma;
- EF Non-Op, LLC, a Texas limited liability company formed on December 1, 2010. EF Non-Op holds interests in oil and natural gas properties located in La Salle County, Texas;
- Sabine River Energy, LLC, a Texas limited liability company formed on May 18, 2011. Sabine holds interests in oil and natural gas properties located in Texas, Louisiana and Oklahoma.
- Basic Petroleum Services, Inc. ("BPS"), a Texas corporation formed March 30, 1977. BPS is a service company which provides services to one of the fields that the Company operates in South Texas.

All intercompany accounts and transactions are eliminated in consolidation.

Use of Estimates

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States 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. Estimates and assumptions that, in the opinion of the Company's management, are significant include oil and natural gas reserves and the related cash flow estimates used in depletion and impairment of oil and natural gas properties, the evaluation of unproved properties for impairment, fair value estimates, asset retirement obligations, oil and natural gas revenue accruals, lease operating expense accruals, and capital accruals. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's consolidated financial statements.

Cash and Cash Equivalents

Cash and cash equivalents consists of all demand deposits and funds invested in highly liquid investments with an original maturity date of three months or less.

Accounts Receivable

Accounts receivable include amounts due from crude oil, natural gas, and NGL purchasers, other operators for which the Company holds an interest, and from non-operating working interest owners. Accrued crude oil, natural gas, and NGL 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. At December 31, 2014, 2013, and 2012, the Company did not have an allowance for doubtful accounts as all accounts receivable were deemed collectible by management.

Advances

The Company, in its execution of its drilling program has other working interest partners. The Company, through its joint operating agreements, requires its working interest partners to pay a drilling advance for their share of the estimated drilling and completion costs. Until such advances are applied to actual drilling and completion invoices, the Company carries the advance as a current liability on its balance sheet. The Company expects such advances to be applied against the partners' joint interest billings for its share of drilling operations.

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 for hedge accounting. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated values of derivative contracts held at the balance sheet date are recognized in "Net gain (loss) on derivative contracts" in the Consolidated Statement of Operations as unrealized gains or losses on derivative contracts. Realized gains or losses on derivative contracts are also recognized in "Net gain (loss) on derivative contracts" in the Consolidated Statements of Operations.

Proved Oil and Gas Properties

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred by the Company related to the acquisition of oil and gas properties and the cost of drilling development wells and successful exploratory wells are capitalized. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are charged to operations as incurred. Upon sale of oil and 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. If additions to proved oil and gas properties will be paid within twelve months of year-end, then such additions are accrued at year-end and are included in "*Additions to oil and gas property and equipment*" financial statement line item on the Consolidated Statements of Cash Flows. Gains and losses arising from the sale of properties are included in operating income (loss) on the Consolidated Statement of Operations.

The Company's lease acquisition costs and development costs of proved oil and 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 gas producing property and related equipment was $18.1 million, $16.9 million, and $12.2 million, for the years ended December 31, 2014, 2013, and 2012, respectively.

Proved oil and gas properties are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the expected future cash flow expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, then the carrying value is written down to its estimated fair value.

Each component of an impairment calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, estimated future net cash flows, and fair value. The Company recognized impairments of $16.9 million, $9.8 million, and $43.9 million for the years ended December 31, 2014, 2013, and 2012, respectively, on proved oil and gas properties.

Unproved Oil and 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. If additions to unproved oil and gas properties will be paid within twelve months of year-end, then such additions are accrued for at year-end and are included in the "*Additions to oil and gas property and equipment*" financial statement line item on the Consolidated Statements of Cash Flows. Unproved oil and 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.

Unproved properties are assessed periodically to determine whether they have been impaired based on remaining lease term, drilling results, reservoir performance, seismic interpretation, or future plans to develop acreage.

The Company recognized impairments of $2.5 million, $2.5 million, and $8.6 million for the years ended December 31, 2014, 2013, and 2012, respectively, on unproved oil and gas properties.

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles—Goodwill and Other* (ASC 350). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. The company carried goodwill as of December 31, 2014 related to the reverse acquisition with Earthstone and the 2014 Eagle Ford Acquisition. See Note 3 "*Acquisitions and Divestitures*" for further discussion regarding the goodwill associated with the transactions.

Accounting Standards Update (ASU) No. 2011-08, *Testing for Goodwill Impairment* (ASU 2011-08), simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying value. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then the entity does not have to perform the two-step impairment test. However, if the same conclusion is not reached, the entity is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying value of the reporting unit. If the carrying value exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of impairment loss, if any. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test.

Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon, remediate oil and gas wells, remove equipment and facilities from leased acreage, and return land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when a well is completed or acquired or when an asset is installed at the producing location), and the costs of such liability increases the carrying amount of the related long-lived asset by the same amount.

After the liability is initially recorded, the carrying amount of the related long-lived asset is increased over time through a charge to accretion expense each period and the capitalized cost is depleted on a units-of-production basis based on the proved developed reserves of the related assets. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability. See Note 9 "*Asset Retirement Obligations*" for further disclosure regarding the asset retirement obligation.

Business Combinations

The Company accounts for the acquisition of oil and gas properties, that are not commonly controlled, based on the requirements of ASC Topic 805, which requires an acquiring entity to recognize the assets acquired and liabilities assumed at fair value under the acquisition method of accounting, provided such assets and liabilities qualify for acquisition accounting under the standard. The Company accounts for property acquisitions of proved oil and gas property as business combinations.

Revenue Recognition

Oil, natural gas, and NGL revenues represent income from production and delivery of oil, natural gas, and NGL, recorded net of royalties. Revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has been transferred, and collectability of the revenue is probable. The Company follows the sales method of accounting for gas imbalances. The Company had no significant gas imbalances as of December 31, 2014, 2013, or 2012.

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 NGL production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts. In 2014 and 2013, one purchaser accounted for 60% and 21%, of the Company's oil, natural gas, and NGL revenues, respectively. No other purchaser accounted for 10% or more of the Company's oil, natural gas, and NGL revenues during 2014, 2013, and 2012.

The Company holds working interests in oil and gas properties for which a third party serves as operator. The operator sells the oil, natural gas, and NGL to the purchaser, collects the cash, and distributes the cash to the Company. The Company recognizes the cash received as revenue. In 2014, one operator distributed 20% of the Company's oil, natural gas and NGL revenues. In 2013, two operators distributed 47% and 11% of the Company's oil, natural gas, and NGL revenues. In 2012, two operators distributed 65% and

18% of the Company's oil, natural gas, and NGL revenues. No other operator accounted for 10% or more of the Company's oil, natural gas, and NGL revenues during 2013, 2012, and 2011.

If purchasers and operators fail to perform pursuant to contractual terms, then the Company's overall business may be adversely impacted. The Company's management believes this risk is mitigated by the size, and reputation, of its purchasers and operators.

Commodity derivative contracts held by the Company are with two counterparties. Both counterparties are participants in the Company's credit facility and possess investment-grade ratings from Moody's and Standard & Poor.

The Company regularly maintains its cash in bank deposit accounts. Balances held by the Company at its bank 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. The Company's management believes this risk is not significant based upon the size and reputation of the financial institutions.

Income Taxes

The provision for income taxes is based on taxes payable or refundable for the current year and deferred taxes on differences between the tax bases of assets and liabilities and their reported amounts in the consolidated financial statements, which result from temporary differences between the amount of taxable income and pretax financial income. Deferred tax assets and liabilities are included in the 2014 consolidated financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. Tax positions are evaluated for recognition and measurement, with deferred tax balances recorded at their anticipated settlement amounts. A valuation allowance is provided for deferred tax assets not expected to be realized. As noted in the Principles of Consolidation the historical financials are those of OVR. OVR is not subject to taxation and therefore tax provisions were not recorded on the historical consolidated financial statements. As result of the Exchange Agreement, Oak Valley as result of its change in tax status is now taxable and is subject to taxation and included in the purchase accounting adjustments is a charge to earnings to record a tax provision.

The Company follows the provisions of FASB ASC Topic 740, *Income Taxes* ("ASC Topic 740"), relating to accounting for uncertainties in income taxes. ASC Topic 740 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. ASC Topic 740 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. ASC Topic 740 also provides guidance on measurement, classification, interest and penalties and disclosure. Tax positions taken related to the Company's pass-through status and state income tax liability, including deductibility of expenses, have been reviewed and the Company's management is of the opinion that material positions taken by the Company 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, 2014, 2013, or 2012. The 2011 through 2014 tax years generally remain subject to examination.

Recently Issued Accounting Pronouncements

In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers. The objective of this guidance is to establish principles for reporting information about the nature, timing, and uncertainty of revenue and cash flows arising from an entity's contracts with customers, including qualitative and quantitative disclosures around contracts with customers, significant judgments and change in judgments, and assets recognized from the costs to obtain or fulfill a contract. The standards update is effective for interim and annual periods beginning after December 15, 2016. We will adopt this standards update, as required, beginning with the first quarter of 2017. The Company is in the process of evaluating the impact, if any, of this guidance on its consolidated financial statements.

Note 3. Acquisitions and Divestitures

Earthstone Energy Reverse Acquisition

On December 19, 2014, the Company and OVR closed the transactions contemplated by the Exchange Agreement dated May 15, 2014 and as amended September 26, 2014 between the Company and OVR whereby OVR contributed to the Company the membership interests of its three wholly-owned subsidiaries, which included producing assets, undeveloped acreage and substantially all of its cash of approximately $130 million, inclusive of approximately $107 million in cash received from members' capital commitments received immediately prior to the Exchange. OVR received approximately 9.1 million shares of newly issued common stock, $0.001 par value per share (the “Common Stock”), of the Company. The Exchange resulted in a change of control of the Company. The Exchange has been accounted in accordance with FASB ASC805, Business Combinations (“ASC 805”) as a reverse acquisition whereby Oak Valley is considered the acquirer for accounting purposes and Earthstone is the acquiree. ASC 805 also requires, that among other things, assets acquired and liabilities assumed to be measured at their acquisition date fair values. The results of operations from Earthstone’s legacy assets are reflected in the Company’s consolidated statement of operations beginning December 19, 2014.

An allocation of the purchase price was prepared using, among other things, the year-end reserve report prepared by Cawley, Gillespie and Associates, Inc. that was adjusted and re-priced by the Company’s reserve engineering staff back to December 19, 2014. The following allocation is still preliminary with respect to final tax amounts, pending the completion of the 2014 Earthstone Energy, Inc. tax return and certain accruals and includes the use of estimates based on information that was available to management at the time these audited consolidated financial statements were prepared. Additional changes to the purchase price allocation may result in a corresponding change to goodwill in the period of the change.

The following table summarizes the consideration paid to acquire the legacy Earthstone net assets and the estimated values of those net assets (*in thousands, except share and share price amounts*):

Shares of Common Stock outstanding before the Exchange		1,734,988
Company director and officer restricted shares that vested in the Exchange		18,400
Shares of Common Stock issued in the Exchange		9,124,452
Total shares of Common Stock outstanding following the Exchange		10,877,840
Shares of Common Stock issued as consideration		1,753,388
Closing price of Common Stock (1)	$	19.08
Total purchase price	$	33,455
Estimated Fair Value of Liabilities Assumed:		
Current liabilities	$	7,852
Long-term debt		7,000
Deferred tax liability (2)		2,880
Asset retirement obligation		2,227
Amount attributable to liabilities assumed		19,959
Total purchase price plus liabilities assumed	$	53,414
Estimated Fair Value of Assets Acquired:		
Cash (3)	$	2,920
Other current assets		3,466
Proved oil and natural gas properties (4) (5)		21,813
Unproved oil and natural gas properties		5,524
Other non-current assets		745
Amount attributable to assets acquired	$	34,468
Goodwill (6)	$	18,946

(1) The share prices used for the determination of the purchase price was the adjusted closing price of the Common Stock on December 19, 2014.

(2) This amount represents the recorded book value versus tax value difference in oil and natural gas properties and other net assets as of the date the Exchange on a tax effected basis of approximately 35%. The tax basis of the legacy Earthstone assets were not adjusted in the Exchange. As noted above, however, ASC 805 requires that the Company in a reverse acquisition record the legacy Earthstone net assets at fair value on the date of the Exchange; the fair value of the net assets was in excess of the tax basis and as such required the recognition of a deferred tax liability.

(3) The components of cash flow in the Exchange transaction in which the legacy Earthstone assets were acquired was $7.1 million in notes payable and accrued interest that was paid in full in conjunction with the Exchange less the cash acquired of $2.9 million.

(4) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $51.62 per barrel of oil and $4.58 per Mcf of natural gas after adjustments for transportation fees and regional price differentials.

(5) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates 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. For additional information on Level 3 inputs, see *Note 5 Fair Value Adjustments*.

(6) Goodwill was determined to be the excess consideration exchanged over the fair value of the Company's net assets on December 19, 2014. The goodwill recognized will not be deductible for tax purposes.

2014 Eagle Ford Acquisition Properties

Also on December 19, 2014, immediately following the Exchange,Flatonia Energy, LLC ("Flatonia"), Parallel Resource Partners, LLC ("Parallel"), and a wholly owned subsidiary of the Company, Sabine, closed the transactions contemplated by the Contribution Agreement dated October 16, 2014 (the "Contribution Agreement"), by and among the Company, OVR, Sabine, Oak Valley Operating, LLC, Parallel, and Flatonia, whereby Parallel contributed 28.57% of the oil and gas property interests held by Flatonia, a wholly owned subsidiary of Parallel, in consideration for approximately 2.96 million shares of Common Stock (the "Contribution"). The assets subject to the Contribution Agreement were certain oil and gas property interests in producing wells and acreage in the Eagle Ford trend of Texas (the "2014 Eagle Ford Acquisition Properties"). One of the subsidiaries included in the Exchange is the operator of the 2014 Eagle Ford Acquisition Properties. The only relationship that Flatonia or Parallel had with this subsidiary or the Company prior to the transaction was that the subsidiary is the operator of the 2014 Eagle Ford Acquisition Properties. The Contribution is being accounted for as a business combination in accordance ASC 805 which among other things requires the assets acquired and liabilities assumed to be measured and recorded at their fair values as of the acquisition date.

An allocation of the purchase price was prepared using, the year-end reserve report prepared by Cawley, Gillespie and Associates, Inc. that was adjusted and re-priced by the Company's reserve engineering staff back to December 19, 2014. The following allocation is still preliminary with respect to final tax amounts, pending the completion of the 2014 Flatonia Energy, LLC tax return and certain accruals, it includes the use of estimates based on information that was available to management at the time these audited consolidated financial statements were prepared. The Company's final allocation of purchase price is dependent on the seller's tax return because Earthstone received carryover basis on Flatonia's assets and liabilities because the Contribution Agreement was not a taxable transaction under the United States Internal Revenue Code of 1986, as amended. Additional changes to the purchase price allocation may result in a corresponding change to goodwill in the period of the change.

The following table summarizes the consideration paid to acquire the 2014 Eagle Ford Acquisition Properties and the estimated values of those net assets (*in thousands, except share and share price amounts*):

Shares of Common Stock issued as consideration in the Contribution		2,957,288
Closing price of Common Stock (1)	$	19.08
Total purchase price	$	56,425
Estimated Fair Value of Liabilities Assumed:		
Deferred tax liability (2)	$	4,046
Asset retirement obligation		173
Amount attributable to liabilities assumed		4,219
Total purchase price plus liabilities assumed	$	60,644
Estimated Fair Value of Assets Acquired:		
Proved oil and natural gas properties (3) (4)	$	34,745
Unproved oil and natural gas properties		21,853
Amount attributable to assets acquired	$	56,598
Goodwill (5)	$	4,046

(1) The share price used for the determination of the purchase was the adjusted closing price of Common Stock on December 19, 2014, the day the Contribution closed.
(2) This amount represents the recorded book value to tax difference of the oil and natural gas properties as of the date of the close of the Contribution agreement on a tax effected basis of approximately 34%. As noted above, the Company received the net assets acquired at Flatonia's carryover tax basis, however ASC 805 requires assets acquired and liabilities assumed be

measured at their fair values as of the acquisition date; the fair value of the 2014 Eagle Ford Acquisition Properties on December 19, 2014 was in excess of the tax basis and as such required the recognition of a deferred tax liability.

(3) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $56.36 per barrel of oil and $3.36 per Mcf of natural gas after adjustments for transportation fees and regional price differentials.

(4) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates 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. For additional information on Level 3 inputs, see *Note 5 Fair Value Adjustments*.

(5) Goodwill was determined as the excess consideration exchanged over the fair value of the 2014 Eagle Ford Acquisition Properties on December 19, 2014. Goodwill recognized will not be deductible for tax purposes.

The following unaudited pro forma combined condensed results of operations are provided for the years ended December 31, 2014 and 2013 as though the Exchange and Contribution had been completed as of the beginning of the comparable prior annual reporting period, or January 1, 2013. The pro forma combined results of operations for the years ended December 31, 2014 and 2013 were been prepared by adjusting the historical results of the Company to include the historical results of the legacy Earthstone properties and the 2014 Eagle Ford Acquisition Properties. These 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. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the Exchange or Contribution or any estimated costs that will be incurred to integrate the legacy Earthstone net assets and the 2014 Eagle Ford Acquisition Properties. Future results may vary significantly from the results reflected in this unaudited pro forma financial information because future events and transaction, as well as other factors (*in thousands, expect per share amounts*).

	Years ended December 31,	
	2014	2013
	(Unaudited)	
Revenue	$ 85,633	$ 66,450
Income before taxes	$ 16,196	$ 2,460
Net income available to Earthstone common stockholders	$ 10,672	$ 1,610
Pro forma net loss per common share:		
Basic and diluted	$ 0.77	$ 0.12

The Company's historical financial information were adjusted to give effect to the pro formas events that were directly attributable to the Exchange and the Contribution and were factually supportable. The unaudited pro forma consolidated results include the historical revenues and expenses of the assets acquired and liabilities assumed in the transactions noted above with the following adjustments:

- Adjustments to recognize incremental depletion expense under the successful efforts method of accounting based on the fair value of the oil and natural gas properties and incremental accretion expense based on the asset retirement costs of the oil and natural gas properties acquired;
- Eliminate historical interest expense for the legacy Earthstone debt that was retired;
- Eliminate transaction costs and non-recurring charges directly related to the transactions that were included in the historical results of operations for Earthstone and OVR in the amount of $3.3 million. Transaction costs directly related to the transactions that do not have a continuing impact on the combined Company's operating results have been excluded from the 2014 and 2013 pro forma earnings;
- Adjustments to recognize pro forma income tax based on an assumed approximate 35% rate;
- Adjustments to convert the full cost method financial statement of Earthstone to successful efforts financial statements which included adjusting exploration expense which would not have been capitalized under successful efforts method of accounting for oil and natural gas activities; and
- Adjustment to eliminate the non-recurring deferred tax expense charge for the conversion of the Oak Valley subsidiaries from a non-taxable partnership to a taxable corporation.

For the year ended December 31, 2014, the Company recognized $0.5 million of oil, natural gas and natural gas liquids sales related to the legacy Earthstone assets and operating expenses of $0.3 million. Additionally, non-recurring transaction costs of $0.9 million were

included in the consolidated statement of operations in “General and administrative” expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented above.

For the year ended December 31, 2014, the Company recognized $0.6 million of oil, natural gas and natural gas liquids sales related to the 2014 Eagle Ford Acquisition Properties and operating expenses of $0.1 million. Additionally, non-recurring transaction costs of $0.2 million are included in the consolidated statement of operations in “General and administrative” expenses; these non-recurring transaction costs have been excluded from the pro forma results for all periods presented above.

2013 Eagle Ford Acquisition

In July 2013 and August 2013, the Company purchased producing wells and acreage in the Eagle Ford shale trend of South Texas for approximately $71.6 million and $15.1 million, respectively (the “2013 Eagle Ford Acquisition”). The 2013 Eagle Ford Acquisition was accounted for as a business combination in accordance with ASC Topic 805, which among other things, requires assets acquired and liabilities assumed to be measured at fair value as of the effective date of the acquisition. The effective date of the 2013 Eagle Ford Acquisition was January 1, 2013. The estimated fair value of the properties approximates the fair value of consideration, and as a result, no goodwill was recognized.

The following table summarizes the consideration paid to acquire the properties and the amounts of the assets acquired and liabilities assumed:

(In thousands)		
Purchase price	$	86,687
Allocation of purchase price:		
Proved properties (1) (2)	$	57,255
Unproved properties		30,041
Asset retirement obligations		(609)
Total	$	86,687

(1) The weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $99.32 per barrel of oil and $3.24 per Mcf of natural gas after adjustments for transportation fees and regional price differentials.

(2) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates 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. For additional information on Level 3 inputs, see *Note 5 Fair Value Adjustments*.

The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2013 and 2012 as if the 2013 Eagle Ford Acquisition had been completed as of the beginning of the comparable prior annual reporting period, or January 1, 2012. The pro forma combined results of operations for the years ended December 31, 2013 and 2012 have been prepared by adjusting historical results of the Company to include the historical results of the 2013 Eagle Ford Acquisition. These 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. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the Eagle Ford Acquisition or any estimated costs that will be incurred to integrate the 2013 Eagle Ford Acquisition. Future results may vary significantly from the results reflected in this unaudited pro forma financial information because of future events and transactions, as well as other factors.

The unaudited pro forma consolidated results include the Company’s historical financial information and the revenues and expenses of assets acquired and liabilities assumed in the 2013 Eagle Ford Acquisition (*in thousands except share amounts*):

	Years ended December 31,	
	2013	2012
	(Unaudited)	
Revenue	$ 48,291	$ 39,804
Loss before taxes	$ (5,240)	$ (39,796)
Net loss available to Earthstone common stockholders	$ (3,406)	$ (25,867)
Pro forma net loss per common share:		
Basic and diluted	$ (0.37)	$ (2.83)

The Company's historical financial information was adjusted to give effect to the pro formas events that were directly attributable to 2013 Eagle Ford Property acquisition and were factually supportable. The unaudited pro forma consolidated results include the historical revenues and expenses of the assets acquired and liabilities assumed in the transactions noted above with the following adjustments:

- Adjustments to recognize incremental depletion expense under the successful efforts method of accounting based on the fair value of the oil and natural gas properties and incremental accretion expense based on the asset retirement costs of the oil and natural gas properties acquired;
- Eliminate transaction costs and non-recurring charges directly related to the transactions that were included in the historical results of operations for OVR in the amount of $1.1 million. Transaction costs directly related to the transactions that do not have a continuing impact on the Company's operating results have been excluded from the 2013 and 2012 pro forma earnings; and
- Adjustments to recognize pro forma income tax based on an assumed approximately 35% rate.

The amount of revenue and net income from the 2013 Eagle Ford Acquisition included in the Company's Consolidated Statement of Operations for the year ended December 31, 2013, was $9.5 million and $6.2 million, respectively.

Acquisition costs of $1.1 million, are included in "*General and administrative expense*" in the Consolidated Statement of Operations.

2013 Divestitures

In May 17, 2013, OVR sold undeveloped acreage and working interest in nine wells located in Guadalupe County, Texas, and Caldwell County, Texas for cash consideration of $0.5 million. OVR recorded a loss on sale of $0.1 million. The effective date of the sale was April 1, 2013.

On March 28, 2013, OVR sold undeveloped acreage in Harrison County, Texas, and the working interest in one well for cash consideration of one hundred dollars. OVR recorded a loss on sale of $0.1 million. The effective date of the sale was April 1, 2013.

2012 Acquisitions and Divestitures

On December 18, 2012, OVE assigned all of the membership interests of one of its wholly owned subsidiaries (the "Assigned Subsidiary") to an entity unaffiliated with OVE and OVR. The consolidated financial statements include the accounts of the Assigned Subsidiary through the date of assignment. Prior to the assignment, in February 2012, the OVR predecessor closed on a sale of all of the oil and natural gas assets of the Assigned Subsidiary for cash consideration of $8.5 million. The OVR predecessor used $5.2 million of the proceeds to pay down its credit facility and the remainder to fund capital expenditures and for general corporate purposes. The OVR predecessor recorded a $4.1 million gain on the sale.

On April 4, 2012, the OVR predecessor acquired various working interests in certain wells and undeveloped acreage in Caddo and DeSoto Parishes, Louisiana, for cash consideration of $1.6 million. The OVR predecessor acquired working interests in 19 wells, including additional interests in eight wells operated by OVO. The effective date of the acquisition was January 1, 2012.

On March 8, 2012, the OVR predecessor sold working interests and unitized producing acreage in two wells in Lincoln and Webster Parishes, Louisiana, for cash consideration of $0.1 million. The OVR predecessor recorded a gain on sale of $0.1 million. The effective date of the sale was January 1, 2012.

On March 8, 2012, the OVR predecessor sold working interests in six wells in exchange for a working interests in one well, and cash consideration received by the Company of $1.1 million. The wells are located in DeSoto Parish, Louisiana. The OVR predecessor recorded a gain on sale of $0.6 million. The effective date of the exchange was January 1, 2012.

On February 16, 2012, the OVR predecessor sold certain assets located in Ouachita Parish, Louisiana. The sale consisted of approximately 395 net acres of unproved leasehold in the Cadeville Prospect and one well in progress in exchange for cash consideration of $0.4 million. The OVR predecessor recorded a gain on sale of $0.1 million. The effective date of the sale was February 1, 2012.

On February 7, 2012, the OVR predecessor acquired working interests in certain sections of the NW Caldwell Prospect located in Caldwell County, Texas, for cash consideration of $1.0 million. The acquired leasehold added approximately 1,973 net acres of unproved leasehold to the NW Caldwell Prospect, all of which was subsequently divested on May 17, 2013. The effective date of the acquisition was January 25, 2012.

Note 4. Derivative Financial Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are utilized to economically hedge the Company’s exposure to price fluctuations and reduce the variability in the Company’s cash flows associated with anticipated sales of future oil and natural gas production. The Company follows FASB ASC Topic 815 *Derivatives and Hedging* (“ASC Topic 815”), to account for its derivative financial instruments. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company’s policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive. The counterparties to the Company’s current derivative contracts are lenders in the Company’s Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company’s Credit Agreement.

The Company’s crude oil and natural gas derivative positions consist of swaps. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in “*Net gain on derivative contracts*” on the Consolidated Statements of Operations. All derivative contracts are recorded at fair market value and included in the Consolidated Balance Sheets as assets or liabilities.

With an individual derivative counterparty, the Company may have multiple hedge positions that expire at various points in the future and result in fair value asset and liability positions. At the end of each reporting period, those positions are offset to a single fair value asset or liability for each commodity, and the netted balance is reflected in the Consolidated Balance Sheets as an asset or a liability.

The Company nets its derivative instrument fair value amounts executed with the same 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 Company had the following open crude oil and natural gas derivative contracts as of December 31, 2014:

Period	Instrument	Commodity	Volume in MMBtu / Bbls	Fixed Price
January 2015 - March 2015	Swap	Natural Gas	150,000	$ 4.175
January 2015 - March 2015	Swap	Natural Gas	75,000	$ 4.30
January 2015 - June 2015	Swap	Crude Oil	21,000	$ 91.50
January 2015 - December 2015	Swap	Crude Oil	66,000	$ 95.10

In March 2015, the Company entered into a crude oil swap contract. The crude oil swap has a term of April 2015 through March 2016 and provides 5,000 Bbls per month. The swap has a fixed price of $57.00 per Bbl.

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 as of December 31, 2014 and 2013 *(in thousands)*:

		December 31, 2014			December 31, 2013		
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	Current derivative assets	$ 3,569	$ —	$ 3,569	$ 154	$ —	$ 154
Commodity contracts	Current derivative liabilities	$ —	$ —	$ —	$ (172)	$ —	$ (172)
Commodity contracts	Noncurrent derivative liabilities	$ —	$ —	$ —	$ (28)	$ —	$ (28)

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 *(in thousands)*:

		Years Ended December 31,	
		2014	**2013**
Derivatives not designated as hedging contracts under ASC Topic 815	**Statement of Operations Location**		
Unrealized gain (loss) on commodity contracts	Net gain on derivative contracts	$ 3,614	$ (45)
Realized gain on commodity contracts	Net gain on derivative contracts	$ 778	$ 341
		$ 4,392	$ 296

The Company did not have derivative contracts as of December 31, 2012.

Note 5. Fair Value Measurements

FASB ASC Topic 820, *Fair Value Measurements and Disclosure ("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, 2014.

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 Company's model is validated by the counterparty's marked-to-market statements. 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, 2014	Level 1	Level 2	Level 3	Total
Financial assets				
Current derivative assets	$ —	$ 3,569	$ —	$ 3,569
Total financial assets	$ —	$ 3,569	$ —	$ 3,569
Financial liabilities				
Current derivative liabilities	$ —	$ —	$ —	$ —
Noncurrent derivative liabilities	—	—	—	—
Total financial liabilities	$ —	$ —	$ —	$ —
December 31, 2013				
Financial assets				
Current derivative assets	$ —	$ 154	$ —	$ 154
Total financial assets	$ —	$ 154	$ —	$ 154
Financial liabilities				
Current derivative liabilities	$ —	$ 172	$ —	$ 172
Noncurrent derivative liabilities	—	28	—	28
Total financial liabilities	$ —	$ 200	$ —	$ 200

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

Asset Impairment

Oil and gas properties are measured at fair value on a nonrecurring basis. The impairment charge reduces the carrying values of oil and gas properties' 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 gas properties are based on (i) proved reserves, (ii) forward commodity prices and assumptions as to costs and expenses, and (iii) the estimated discount rate that would be used by potential purchasers to determine the fair value of the assets.

The Company recorded asset impairments of $16.9 million, $9.8 million and $43.9 million on proved properties during the years ended December 31, 2014, 2013, and 2012, respectively.

The Company recorded asset impairments of $2.5 million, $2.5 million, and $8.6 million on unproved properties during the years ended December 31, 2014, 2013, and 2012, respectively. All of the 2014, 2013, and 2012 impairments were included in impairment expense.

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 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 Obligation

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 9, "*Asset Retirement Obligations*" for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

Note 6. Equity

Earnings (Loss) Per Common Share

Basic earnings per share is computed by dividing net income attributable to common shares by the basic weighted-average shares of common stock outstanding during the period. The calculation of diluted earnings per share is similar to basic, except the denominator includes the effect of dilutive common stock equivalents. Common stock equivalents include awards issued under the Company's long-term incentive plan discussed in Note 7" *Stock Based Compensation"*. The Company had no outstanding common stock equivalents for the years ended December 31, 2014, 2013, and 2012.

The following table is a reconciliation of net income and weighted-average common shares outstanding for purposes of calculating basic and diluted loss per share. The number of shares for the years ended December 31, 2013 and 2012, reflect the shares issued to Oak Valley Resources, LLC on December 19, 2014 as a result of the Exchange Agreement that was accounted for as a reverse acquisition.

	Years Ended December 31,		
(In thousands, except per share amounts)	2014	2013	2012
Net loss	$ (28,834)	$ (19,875)	$ (53,321)
Weighted average common shares outstanding:			
Basic	9,279	9,124	9,124
Diluted	9,279	9,124	9,124
Net loss per share:			
Basic	$ (3.11)	$ (2.18)	$ (5.84)
Diluted	$ (3.11)	$ (2.18)	$ (5.84)

Members' Equity

As was explained in *Note 2 – Summary of Significant Account Policies – Principles of Consolidation* the historical financial information contained in the Annual Report on Form 10-K is that of OVR and its subsidiaries. OVR was formed on December 14, 2012. On December 21, 2012, OVR was capitalized by affiliates of EnCap via the contribution of certain oil and gas properties which were conveyed by assigning 100% of the issued and outstanding membership interests in ECC VI, LLC and 100% of the issued and outstanding membership interest in Oak Valley Energy, LLC in exchange for membership interests in OVR. Also on December 21, 2012, EnCap, Wells Fargo, VILLco, and OVM committed an aggregate of $150.0 million in exchange for additional membership interests in OVR. On April 25, 2013, OVR closed a private placement offering amongst accredited investors that raised $62.8 million in capital commitments in exchange for membership interests in OVM. During 2013 OVM members committed an additional $1.7 million (collectively "Investors").

Capital Call Notices

In January 2013, OVR received cash investments in the amount of $16.8 million related to its first capital call notice sent to Wells Fargo, VILLco, and OVM.

In May 2013, OVR received cash investments in the amount of $23.7 million related to its second capital call notice to Investors.

In June 2013, OVR received cash investments in the amount of $67.0 million related to its third capital call notice to Investors.

In December 2014, OVR received cash investments in the amount of $107.0 million related to its third capital call notice to Investors.

Common Stock

On December 19, 2014, pursuant to the Exchange Agreement, the Company issued to OVR 9,124,452 shares (the "Exchange Shares") of Earthstone common stock, par value $0.001 per share in exchange for the outstanding membership interests of OVR's three subsidiaries. The issuance of the Exchange Shares is exempt from registration as a private placement under Section 4(a)(2) of the Securities Act of 1933, as amended (the "Securities Act"), and Rule 506 promulgated thereunder, among other exemptions.

Pursuant to the Contribution Agreement, OVR, through its wholly owned subsidiary, Sabine, acquired a 20% undivided ownership interest in certain oil and gas properties located in Fayette and Gonzales Counties, Texas, in exchange for the issuance of 2,957,288 shares (the "Contribution Shares") of Earthstone common stock to Flatonia Energy, LLC. The issuance of Contribution Shares is exempt from registration as a private placement under Section 4(a)(2) of the Securities Act, and Rule 506 promulgated thereunder, amount other exemption.

Note 7. Stock Based Compensation

2014 Long-Term Incentive Plan

In December 2014, stockholders approved and adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"), which was effective upon the December 19, 2014 closing of the Exchange Agreement with OVR and shall remain in effect until the day prior to the tenth anniversary thereof. Under the 2014 Plan, the Company may grant stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards to Company employees or those of its subsidiaries or affiliates. The Company may also grant nonqualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, stock awards and other incentive awards to any persons rendering consulting or advisory services and non-employee directors, subject to the conditions set forth in the 2014 Plan. Generally, all classes of Company employees are eligible to participate in the 2014 Plan.

The 2014 Plan currently provides that a maximum of 750,000 shares of common stock may be issued in conjunction with awards granted under the 2014 Plan. Awards that are forfeited under the 2014 Plan will again be eligible for issuance as though the forfeited awards had never been issued. Similarly, awards settled in cash will not be counted against the shares authorized for issuance upon exercise of awards under the 2014 Plan.

The 2014 Plan limits the aggregate number of shares of common stock that may be covered by stock options and/or stock appreciation rights granted to any eligible employee in any calendar year to 250,000 shares. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with awards (other than stock options or stock appreciation rights) granted to any eligible employee in any calendar year to 150,000 shares. The 2014 Plan also limits the maximum aggregate amount that may be paid in cash pursuant to awards (other than stock options or stock appreciation rights) made to any eligible employee in any calendar year to $2.0 million. At December 31, 2014, there were no shares issued and all 750,000 shares remained available for award.

Note 8. Long-Term Debt

On June 29, 2011, OVE entered into a new four-year senior secured revolving credit facility (the "OVE Credit Facility"). The OVE Credit Facility was subsequently assumed by OVR on December 21, 2012 (the "OVR Credit Facility"), the date upon which all of the membership interests in OVE were assigned to OVR. In connection with the closing of the Exchange on December 19, 2014, the Company entered into a new credit agreement providing for a $500.0 million four-year senior secured revolving credit facility (the "ESTE Credit Facility"). The OVR Credit facility was refinanced under the "ESTE Credit Facility" and the legacy credit facility of the Company was paid in full and terminated. OVR also assigned to the Company its commodity derivative contracts, which were provided for under the OVR Credit Facility.

Outstanding borrowings under the OVR Credit Facility and the OVE Credit Facility had annual interest rates at either (a) the London Interbank Offered Rate ("LIBOR") plus the applicable utilization margin of 2.25% to 4.25% (2.42% and 2.96% at December 31, 2013 and 2012, respectively) or (b) the base rate plus the applicable utilization margin of 1.00% to 3.00% (4.25% and 4.75% at December 31, 2013 and 2012, respectively). The commitment rate was 0.500% on all unused borrowings.

The initial borrowing base of the ESTE Credit Facility is $80.0 million and is subject to redetermination on the first business day of May and November of each year. At the option of the borrower, the amounts borrowed under the credit agreement bear annual interest rates at either (a) LIBOR plus the applicable utilization margin of 1.50% to 2.50% (1.664% at December 31, 2014) or (b) the base rate plus the applicable utilization margin of 0.50% to 1.50% (3.75% at December 31, 2014) Principal amounts outstanding under the credit facility are due and payable in full at maturity on December 19, 2018. All of the obligations under the credit agreement, and the guarantees of those obligations, are secured by substantially all of the Company's assets. Additional payments due under the credit agreement include paying a commitment fee to the Lender in respect of the unutilized commitments thereunder. The commitment rate ranges from 0.375% to 0.50% per year, depending upon the unutilized portion of the borrowing base in effect from time to time. The Company is also required to pay customary letter of credit fees.

As of December 31, 2014, the Company had $11.2 million of debt outstanding, bearing an interest rate of 1.664%, $0.3 million of letters of credit outstanding and $68.5 million of borrowing base available under its ESTE Credit Facility.

All of the credit facilities discussed herein contain a number of customary covenants that, among other things, restrict, subject to certain exceptions, the Company's ability to incur additional indebtedness, create liens on asset, pay dividends, and repurchase its capital stock. In addition, the Company is required to maintain certain financial ratios, including a minimum current ratio of 1.0 to 1.0 and a maximum annualized quarterly leverage ratio of 4.0 to 1.0. The Company is also required to submit an audited annual report 120 days after the end of each fiscal period. As of December 31, 2014, the Company was in compliance with these covenants under the ESTE Credit Facility.

Interest expense for 2014, 2013 and 2012 includes amortization of deferred financing costs of $0.2 million, $0.1 million, and $48,000, respectively. $1.0 million and $0.5 million, net of amortization, associated with the Company's credit facilities have been capitalized as of December 31, 2014 and 2013, respectively, and are amortized on a straight-line basis over the term of the credit agreements.

Note 9. Asset Retirement Obligations

The Company has asset retirement obligations associated with the future plugging and abandonment of oil and gas properties and related facilities. The accretion of the asset retirement obligation is included in "*Lease operating expense*" in the Consolidated Statements of Operations. 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 2014 and 2013, and in accordance with the provisions of FASB ASC Topic 410*, Asset Retirement and Environmental Obligations (in thousands).*

	2014	2013
Beginning asset retirement obligations	$ 3,011	$ 3,938
Acquisitions[1]	2,742	609
Liabilities incurred	64	316
Accretion expense	317	217
Disposal of properties	(56)	(110)
Revision of estimates	—	(1,959)
Ending asset retirement obligations	$ 6,078	$ 3,011

[1] See Note 3, "*Acquisitions and Divestitures*" for additional information on the Company's acquisition activities.

Based on expected timing of settlement, $0.4 million of the asset retirement obligation is classified as current at December 31, 2014. At December 31, 2013, $70,000 was classified as current.

Note 10. Related Party Transactions

FASB ASC Topic 850, *Related Party Disclosures* ("ASC Topic 850"), requires that transactions with related parties that would make a difference in decision making be disclosed so that users of the financial statements can evaluate their significance. EnCap, the members of OVM, and OVR's Private Placement Investors are considered related parties under ASC Topic 850. The following are significant related party transactions between the Company and parties of Encap and the members of OVM as of and for the years ended December 31, 2014, 2013, and 2012 as well as significant related party transactions between the Company and the OVR Private Placement Investors as of and for the years ended December 31, 2014 and 2013.

The Company employs members of OVM. For the years ended December 31, 2014, 2013 and 2012, the Company made payments totaling $3.9 million, $2.2 million and $0.3 million, respectively, to these members as compensation for services and reimbursement of expenses. The payments are included in "*General and administrative expense*" on the Consolidated Statements of Operations or have been charged out to oil and gas properties.

At December 31, 2013, the Company had a liability of $0.7 million due to members of OVM, which is included in "*Accrued expenses*" on the Consolidated Balance Sheet. At December 31, 2014, the Company did not have a related party asset due from OVM members or a related party liability due to OVM members.

At December 31, 2014 and 2013, the Company had a liabilities of $2.3 million and $0.6 million, respectively, due to companies to which certain members of OVR are significant related parties. These amounts are included in "*Accounts payable*" on the Consolidated Balance Sheet.

As described in Note 6, "*Equity*", all of the authorized Class C Units were issued to OVM. Class C Units entitle OVM to receive distributions from the Company if certain previously agreed upon equity returns are achieved.

As described in Note 2 "*Summary of Significant Accounting Policies*", on December 21, 2012, EnCap assigned all the membership interests in ECC VI and OVE to the Company. These transfers were recorded by the Company at the carrying amounts of the assets and liabilities contributed.

Note 11. Commitments and Contingencies

In the course of its business affairs and operations, the Company is subject to possible loss contingencies arising from federal, state, and local environmental, health and safety laws and regulations and third party litigation.

Commitments

The following table summarizes the Company's estimated future contractual commitments as of December 31, 2014 *(in thousands)*:

	2015	2016	2017	2018	2019	Thereafter
Drilling contracts*	$ 8,682	$ 8,845	$ —	$ —	$ —	$ —
Gas contract**	1,643	1,647	1,643	1,643	1,643	2,327
Office leases	715	639	609	619	575	—
Total	$ 11,040	$ 11,131	$ 2,252	$ 2,262	$ 2,218	$ 2,327

*As of December 31, 2014, the Company had three drilling rigs under contract, of which two contracts have since concluded (January 2015 and February 2015) and the rigs were released as the Company had met all of its contractually agreed to terms within each contract. In 2014, the Company entered into an 18 month contract for a new rig currently being built. The contract provides for a daily drilling rate of $29,000 and in the event the Company does not fulfill its contractual obligations, liquidated damages of up to $10.9 million subject to adjustments could be charged. The rig is scheduled to be completed during the second quarter 2015. As of December 31, 2014, the minimum commitment per the terms of the agreement is approximately $16.0 million.

**As a part of the 2013 Eagle Ford Acquisition as discussed in Note 3 "*Acquisitions and Divestitures*", the Company ratified several long-term gas purchasing and gas processing contracts. As is customary in the industry, the Company has reserved gathering and processing capacity in a pipeline. In one of the contracts, the Company has a volume commitment, whereby the Company pays the owner of the pipeline a fee of $0.45 per MMBtu to hold 10,000 MMBtu per day of capacity for the

Company's use. Since the time of the acquisition, the Company has not been able to meet its delivery commitments. The rate and terms under this purchasing and processing contract expire on June 1, 2021.

The Company leases corporate office space in Houston, Texas and Denver, Colorado. Rent expense was approximately $0.4 million, $0.1 million, and $0.1 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, minimum future lease commitments for subsequent annual periods for all non-cancelable operating leases was approximately $3.2 million.

Contingencies

Environmental

The Company's operations are subject to risks normally associated with the exploration for and the 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, the Company may be involved in various legal proceedings and claims in the ordinary course of business. As of December 31, 2014, and through the filing date of this report, the Company does not believe the ultimate resolution of such actions or potential actions of which the Company is currently aware will have a material effect on its consolidated financial position or results of operations.

Note 12: Income Taxes

As a partnership, OVR was generally not subject to Federal or state income tax on its taxable income. The Partnership's taxable income and deductions were reported by the partners in their respective returns. Therefore, no income taxes were reported by OVR prior to merger date.

The following table shows the components of the Company's income tax provision for 2014 (*in thousands*):

Current:	
Federal	$ —
State	—
Total current	—
Deferred:	
Federal	21,803
State	302
Total deferred	22,105
Total income tax provision	$ 22,105

The following is a reconciliation of taxes computed at the corporate federal statutory income tax rate of 34% to the reported income tax rate provision for the year ended December 31, 2014 (*in thousands, except percentages*):

Net loss before income taxes	$	(6,729)
Tax benefit computed at Federal statutory rate		(2,288)
Non-taxable Oak Valley income prior to merger		(4,142)
Deferred income tax arising from change in tax status of Oak Valley		28,347
State income taxes, net of Federal benefit		188
Total income tax expense	$	22,105
Effective tax rate		-329%

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. The deferred income tax provision for 2014 includes an initial charge of $28.3 million attributable to OVR becoming a taxable entity in December 2014, concurrent with the Reverse Acquisition. Significant components of the deferred tax assets and liabilities at December 31, 2014 are as follows (*in thousands*):

Deferred current income tax assets		
Asset retirement obligation	$	140
Deferred compensation		81
Other		5
Deferred current income tax assets		226
Deferred noncurrent income tax assets (liabilities)		
Office and other equipment		(381)
Oil & gas properties		(29,730)
Asset retirement obligation		1,952
Intangible assets		130
Unrealized derivative gain		(1,229)
Net deferred noncurrent tax assets (liabilities)		(29,258)
Net deferred tax liability	$	(29,032)

As of December 31, 2014, the Company had statutory depletion available for carryforward of approximately $6.3 million, which may be used to offset future taxable income. The amount that may be used in any year is subject to an annual limit of $1.0 million arising from a change in control in 2014.

Uncertain Tax Positions

ASC 740, *Income Taxes* (ASC 740) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As of December 31, 2014, the Company has 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 a consolidated federal 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, 2014, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

On September 13, 2013, the United States Treasury Department and the Internal Revenue Service issued final tangible property regulations (the tangible property regulations) under provisions that include IRC Sections 162, 167 and 263(a). The tangible property regulations apply to amounts paid to acquire, produce or improve tangible property, as well as dispositions of such property. The general effective date of the tangible property regulations are for tax years beginning on or after January 1, 2014. Based on the Company's analysis management did not consider the impacts of the tangible property regulations to be material to the Company's consolidated financial position, its results of operations, or both.

Note 13. Supplemental Selected Quarterly Financial Data (Unaudited)

(In thousands, except per share data)	Three Months Ended, March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Year Ended December 31, 2014				
Oil and gas revenues	$ 11,577	$ 12,059	$ 11,957	$ 12,018
Other revenues	109	86	98	90
Operating expenses	7,777	9,192	10,204	31,407
Operating income (loss)	3,909	2,953	1,851	(19,299)
Other income (expense), net	(1,169)	(1,424)	2,364	4,086
Income tax expense	—	—	—	(22,105)
Net income (loss)	$ 2,740	$ 1,529	$ 4,215	$ (37,318)
Basic net income (loss) per share	$ 0.30	$ 0.17	$ 0.46	$ (3.83)
Diluted net income (loss) per share	$ 0.30	$ 0.17	$ 0.46	$ (3.83)

(In thousands, except per share data)	Three Months Ended, March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Year Ended December 31, 2013				
Oil and gas revenues	$ 3,110	$ 6,209	$ 11,208	$ 9,107
Other revenues	116	80	96	17
Operating expenses	7,049	10,696	10,095	21,803
Operating (loss) income	(3,823)	(4,407)	1,209	(12,679)
Other (expense) income, net	(141)	232	(91)	(175)
Net (loss) income	$ (3,964)	$ (4,175)	$ 1,118	$ (12,854)
Basic net (loss) income per share	$ (0.43)	$ (0.46)	$ 0.12	$ (1.41)
Diluted net (loss) income per share	$ (0.43)	$ (0.46)	$ 0.12	$ (1.41)

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Costs Incurred Related to Oil and Gas Activities

The Company's oil and gas activities for 2014, 2013 and 2012 were entirely within the United States of America. Costs incurred in oil and gas producing activities were as follows (*in thousands*):

	Year Ended December 31,		
	2014 (1)	2013	2012
Acquisition cost:			
Proved	$ 74,728	$ 51,488	$ 1,609
Unproved	36,236	32,863	11,589
Exploration costs:			
Exploratory drilling	-	64	2,013
Geological and geophysical	111	394	-
Development costs	75,105	32,511	24,222
Total additions	$ 186,180	$ 117,320	$ 39,433

(1) Acquisition costs include the fair value of the legacy Earthstone proved properties equal to $22.1 million and $5.5 million of unproved properties that were added in the Exchange Agreement which was accounted for as a reserve acquisition. Acquisitions costs also included $34.7 million and $21.9 million in proved and unproved additions related to the 2014 Eagle Ford Acquisition.

During the years ended December 31, 2014, 2013 and 2013, additions to oil and gas properties of $0.2 million. $1.0 million and $0.1 million were recorded for estimated costs of future abandonment related to new wells drilled or acquired.

The net changes in capitalized exploratory well costs were as follows (*in thousands*):

Oil and Natural Gas Reserves

	December 31,		
	2014	2013	2012
Balance, beginning of year	$ -	$ 2,032	$ 19
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	64	2,013
Capitalized exploratory well costs charged to expense	-	(2,096)	-
Balance, end of year	$ -	$ -	$ 2,032

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, 2014, 2013 and 2012 have been independently prepared by Cawley, Gillespie & Associates, Inc.

The reserve information in this Annual Report on Form 10-K 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 price as of December 31, 2014, 2013, and 2012 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot prices which equates to $94.99 per barrel, $96.94 per barrel, and $94.71 per barrel, respectively. The natural gas prices as of December 31, 2014, 2013 and 2012 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $4.309 per MMBtu, $3.666 per MMBtu and $2.752 per MMBtu, 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 and natural gas reserves for the years ended December 31, 2014, 2013 and 2012 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBOE)
Balance - December 31, 2011	1,182	56,459	-	10,592
Extensions and discoveries	407	3,596	299	1,306
Sale of minerals in place	(301)	(165)	-	(329)
Production	(90)	(2,298)	(76)	(549)
Revision to previous estimates	(679)	(47,493)	169	(8,426)
Balance - December 31, 2012	519	10,099	392	2,594
Extensions and discoveries	3,586	4,198	526	4,812
Sale of minerals in place	(15)	-	-	(15)
Purchases of minerals in place	2,051	709	213	2,382
Production	(163)	(2,635)	(134)	(737)
Revision to previous estimates	100	11,842	321	2,395
Balance - December 31, 2013	6,078	24,213	1,318	11,431
Extensions and discoveries	1,909	1,403	221	2,364
Purchases of minerals in place	7,025	6,064	437	8,473
Production	(403)	(2,132)	(124)	(882)
Revision to previous estimates	(806)	9,031	107	806
Balance - December 31, 2014	13,803	38,579	1,959	22,192
Proved developed reserves:				
December 31, 2012	296	8,245	268	1,938
December 31, 2013	1,307	11,053	557	3,706
December 31, 2014	6,093	16,214	1,005	9,800
Proved undeveloped reserves:				
December 31, 2012	223	1,854	124	656
December 31, 2013	4,771	13,160	761	7,725
December 31, 2014	7,710	22,365	954	12,392

The total proved reserves increase of 10.8 MMBoe during 2014 is comprised of 6.1 MMBoe in proved developed and 4.7 MMBoe in proved undeveloped reserves.

During 2014, the Company added 2.4 MMBoe in proved reserves due to extension and discoveries, the majority of which is due to successful drilling in its operated Eagle Ford property in Fayette and Gonzales counties, Texas. Both new wells drilled and completed during 2014 along with the PUD locations that were added because of this successful drilling contributed to the increase in proved reserves. Purchase of minerals in place of 8.5 MMBoe were as a result of the Exchanges Agreement whereby Oak Valley acquired the legacy Earthstone assets through a reverse acquisition and the Contribution Agreement where the Company acquired additional interests in its operated Eagle Ford property.

The total proved reserves increase of 8.8 MMBoe during 2013 is comprised of 1.8 MMBoe in proved developed and 7.0 MMBoe in proved undeveloped reserves.

During 2013, the Company added 4.8 MMBoe in proved reserves due to successful drilling in both its operated and non-operated Eagle Ford properties. The non-operated Eagle Ford property is located in La Salle county, Texas. Purchases of minerals in place of 2.4 MMBoe were as a result of the purchase, during the second half of 2013, of an approximately 30% working interest of the Company’s operated Eagle Ford property.

The total proved reserves decrease of 8.0 MMBoe during 2012 is comprised of a decrease of 1.6 MMBoe in proved developed and 6.4 MMBoe in proved undeveloped reserves.

During 2012, the Company added 1.3 MMBoe in proved reserves due to successful drilling in it non-operated Eagle Ford property. The Company also sold reserves in place of approximately 0.3 MMBoe and had a downward revision of previous estimates of approximately 8.4 MMBoe. The downward revision was primarily attributable to lower natural gas prices incorporated into the Company's reserve estimates at December 31, 2012 as compared to December 31, 2011.

At December 31, 2014 the Company's estimated proved undeveloped reserves (PUDs) were 12.4 MMBoe, a 4.7 MMBoe net increase over the previous year's estimate of 7.7 MMBoe. The following details the changes in PUD reserves for 2014 (MBoe):

Beginning proved undeveloped reserves at December 31, 2013	7,725
Undeveloped reserves transfer to developed	(1,306)
Revisions	672
Purchases	4,451
Extensions and discoveries	850
Ending proved undeveloped reserves at December 31, 2014	12,392

The majority being 63%, of the Company's PUDs that were transferred from PUD to the developed reserve category occurred in its Eagle Ford property in Fayette and Gonzales counties, TX. The remaining amount that was transferred was in the Company's non-operated Eagle Ford project in La Salle County, TX.

All of the Company's increases through extensions and discoveries occurred in our operated Eagle Ford property in Fayette and Gonzales counties, TX as a result of successful drilling during 2014 which added additional PUD locations as well.

During 2014 we purchased PUD reserves of 4.5 MMBoe as a result of the Exchange Agreement whereby Oak Valley acquired the legacy Earthstone assets and the Contribution Agreement where the Company acquired additional interests in its operated Eagle Ford property.

The revisions to PUD reserves of 672 MBOE occurred primarily as a result of increased gas prices from December 31, 2013 to December 31, 2014 from $3.666/MMBTU to $4.309/MMBTU which increased the number of economic gas-weighted PUD locations and reserves of approximately 1,014 MBOE. This increase was offset by revisions to oil-weighted PUDs related to offsetting producing well performance as well as a decrease in oil prices between December 31, 2013 and December 31, 2014 from $96.94/BO to $94.99/BO.

Based on the Company's year-end 2014 reserve report, the Company expects to drill all of its PUD locations within five years.

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, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

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 ASC 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 engineering staff. 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, 2014, 2013 and 2012, 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. 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 10% discount factor.

The Standardized Measure is as follows (*in thousands*):

	December 31,		
	2014	**2013**	**2012**
Future cash inflows	$ 1,464,138	$ 718,049	$ 88,234
Future production costs	(427,113)	(202,957)	(32,967)
Future development costs	(312,010)	(220,828)	(15,271)
Future income tax expense	(180,248)	-	-
Future net cash flows	544,767	294,264	39,996
10% annual discount for estimated timing of cash flows	(288,911)	(168,907)	(14,864)
Standardized measure of discounted future cash flows	$ 255,856	$ 125,357	$ 25,132

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, 2014 (*in thousands*):

	December 31,		
	2014	**2013**	**2012**
Beginning of year	$ 125,357	$ 25,132	$ 69,240
Sales of oil and gas produced, net of production costs	(35,794)	(20,287)	(10,300)
Sales of minerals in place	-	(380)	(10,274)
Net changes in prices and production costs	(34,681)	241	(6,133)
Extensions, discoveries, and improved recoveries	54,157	48,006	16,375
Changes in income taxes, net (1)	(88,944)	-	-
Previously estimated development costs incurred during the period	18,252	3,227	-
Net changes in future development costs	7,028	(22,966)	14,787
Purchases of minerals in place	163,309	56,069	-
Revisions of previous quantity estimates	16,283	26,259	(54,775)
Accretion of discount	12,536	2,513	6,924
Changes in timing of estimated cash flows and other	18,353	7,543	(712)
End of year	$ 255,856	$ 125,357	$ 25,132

(1) As a result of the December 19, 2014 Exchange, all historical financial information contained in this report is that of OVR and its subsidiaries. OVR, is a partnership for federal tax purposes and is not subject to federal income taxes or state or local income taxes that follow the federal treatment, and therefore OVR did not pay or accrue for such taxes. Pursuant to the Exchange OVR's subsidiaries have become subsidiaries of Earthstone Energy, Inc., which is a taxable entity; as such estimated tax expense was included in the Standardized Measure for December 31, 2014.

Exhibit 21.1

SUBSIDIARIES OF THE COMPANY

Basic Petroleum Services, Inc.

EF Non-Op, LLC

Oak Valley Operating, LLC

Sabine River Energy, LLC

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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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, 2014. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from Earthstone Energy, Inc.'s oil and gas reserves as of December 31, 2014, and Oak Valley Resources, LLC's oil and gas reserves as of December 31, 2013 and 2012 and to the inclusion of our report of Earthstone Energy, Inc. dated February 24, 2015 as an exhibit to the Annual Report on Form 10-K of Earthstone Energy, Inc. for the year ended December 31, 2014.

Sincerely,

Cawley, Gillespie & Assoc., Inc.

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

March 27, 2015

Exhibit 31.1

Certification

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.

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Principal Executive Officer
March 27, 2015

Exhibit 31.2

Certification

I, G. Bret Wonson, 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.

/s/ G. Bret Wonson

G. Bret Wonson
Principal Financial Officer
March 27, 2015

Exhibit 32.1

Section 1350 Certification

I, Frank A. Lodzinski, certify that:

In connection with the Annual Report on Form 10-K of Earthstone Energy, Inc. (the "Company") for the fiscal year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Lodzinski, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Frank A. Lodzinski
Frank A. Lodzinski
President and Chief Executive Officer
March 27, 2015

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

Section 1350 Certification

I, G. Bret Wonson, certify that:

In connection with the Annual Report on Form 10-K of Earthstone Energy, Inc. (the "Company") for the fiscal year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, G. Bret Wonson, Chief Accounting 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.

/s/ G. Bret Wonson
G. Bret Wonson
Chief Accounting Officer
March 27, 2015

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.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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February 24, 2015

Robert Anderson
Executive V.P. – Corporate Development & Engineering
Earthstone Energy, Inc.
1400 Woodloch Forest Dr., Suite 300
The Woodlands, Texas 77380

Re: Evaluation Summary – SEC Price Case
Earthstone Energy, Inc. Interests
Total Proved Reserves
Certain Properties in Various States
As of January 1, 2015

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

Dear Mr. Anderson:

As requested, we are submitting our estimates of total proved reserves and forecasts of economics attributable to the *Earthstone Energy, Inc.* interests in certain properties located in various states. This report includes results for the SEC price case scenario. The results of this evaluation are presented in the accompanying tabulations, with a composite summary presented below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Net Reserves					
Oil	- Mbbl	4,198.2	1,894.5	7,710.9	13,803.6
Gas	- MMcf	12,276.1	3,937.8	22,364.8	38,578.7
NGL	- Mbbl	645.0	360.2	953.9	1,959.2
Net Revenue					
Oil	- M$	374,343.9	172,381.9	694,793.4	1,241,519.4
Gas	- M$	53,936.1	17,021.6	91,993.1	162,950.8
NGL	- M$	19,227.3	10,745.3	29,178.9	59,151.6
Other	- M$	516.5	0.0	0.0	516.3
Severance Taxes	- M$	26,930.7	8,969.3	42,201.5	78,101.5
Ad Valorem Taxes	- M$	5,914.8	3,840.6	15,147.3	24,902.6
Operating Expenses	- M$	133,811.2	28,083.8	124,145.7	286,040.8
Other Deductions	- M$	16,087.2	6,261.8	15,719.3	38,068.4
Investments	- M$	0.0	31,619.5	280,390.8	312,010.3
Net Operating Income (BFIT)	- M$	265,279.9	121,373.7	338,361.0	725,014.6
Discounted @ 10%	**- M$**	**164,433.8**	**70,997.5**	**109,369.3**	**344,800.4**

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

Hydrocarbon Pricing

As requested for the SEC scenario, the base oil and gas prices calculated for December 31, 2014 were $94.99/BBL and $4.309/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 during 2014 and the base gas price is based upon Henry Hub spot prices during 2014. Prices were not escalated in the SEC scenario. Adjustments to oil and gas prices were accepted as provided by your office and may include adjustments for treating cost, transportation charges and/or crude quality and gravity corrections.

Capital, Expenses and Taxes

Capital expenditures, lease operating expenses and Ad Valorem tax values were forecast as provided by your office. 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 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. 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. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

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. The cost of plugging and the salvage value of equipment at abandonment have not been included and, as suggested by your office, are expected to be immaterial.

The reserve estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. Ownership information and economic factors such as liquid and gas prices, price differentials and expenses was furnished by your office. 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.

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. 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