US ENERGY CORP
Form 10-K
April 14, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

þ Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2015

¨ Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to

Commission File Number 000-6814

U.S. ENERGY CORP.
(Exact Name of Company as Specified in its Charter)

Wyoming	**83-0205516**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4643 S. Ulster Street, Suite 970, Denver, Colorado	**80237**
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code:	**(303) 993-3200**

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

Title of each class	Name of exchange on which registered
Common Stock, $0.01 par value	**NASDAQ Capital Market**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ¨ NO þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ¨ NO þ

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES þ NO ¨

Indicate by check mark if disclosure of delinquent filers, pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the 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 þ

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 the definitions of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO þ

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2015): $14,837,000.

The registrant had 28,233,068 shares of its $0.01 par value common stock outstanding as of April 11, 2016.

Documents incorporated by reference: Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2016 annual meeting of stockholders to be filed within 120 days after December 31, 2015.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). All statements other than statements of historical facts are forward-looking statements.

Examples of forward-looking statements in this Annual Report include:

- planned capital expenditures for oil and gas exploration and environmental compliance;
- potential drilling locations and available spacing units, and possible changes in spacing rules;
- cash expected to be available for capital expenditures and to satisfy other obligations;
- recovered volumes and values of oil and gas approximating third-party estimates;
- anticipated changes in oil and gas production;
- drilling and completion activities and opportunities in the Buda, Eagle Ford and other formations in South Texas, the Williston Basin in North Dakota and other areas;
- timing of drilling additional wells and performing other exploration and development projects;
- expected spacing and the number of wells to be drilled with our oil and gas industry partners;
- when payout-based milestones or similar thresholds will be reached for the purposes of our agreements with Statoil, Zavanna and other partners;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Buda, Bakken/Three Forks, Eagle Ford and other formations;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- our expected financial position;
- our expected future overhead reductions;
- our ability to become an operator of oil and gas properties;
- our ability to raise additional financing and acquire attractive oil and gas properties; and
- other plans and objectives for future operations.

These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could,” “up to,” ar and phrases. Though we believe that the expectations reflected in these statements are reasonable, they involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of numerous factors, including, among others:

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
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volatility in oil and gas prices, including further declines in oil prices and/or natural gas prices, which would have a negative impact on operating cash flow and could require further ceiling test write-downs on our oil and gas assets, and which also could adversely impact the borrowing base available under our credit facility with Wells Fargo Bank (sometimes referred to as the "Credit Facility");

- the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);
- the general risks of exploration and development activities, including the failure to find oil and gas in sufficient commercial quantities to provide a reasonable return on investment;
- future oil and gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and gas reserves as they deplete from production;
- environmental risks;
- risks associated with our plan to develop additional operating capabilities, including the potential inability to recruit and retain personnel with the requisite skills and experience and liabilities we could assume or incur as operator or to acquire operated properties or obtain operatorship of existing properties;
- availability of pipeline capacity and other means of transporting crude oil and gas production, and related midstream infrastructure and services;
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;
- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;

- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues; and
- unanticipated down-hole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled “Risk Factors” in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements made above and elsewhere in this Annual Report. 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.

Glossary of Oil and Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcfe. One billion cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

BOE. A barrel of oil equivalent is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquid.

Completion. The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned. Completion of the well does not necessarily mean the well will be profitable.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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 Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory Well. A well drilled to find a new field or a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease Operating Expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

MMBtu. One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Net Acres or Net Wells. Gross acres or wells multiplied, in each case, by the percentage working interest we own.

Net Production. Production that we own less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

Operator. The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

Pay. The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

PV10. The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated 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 non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. 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.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized Measure. The after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated 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 non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART I

Item 1 – Business

Overview

U.S. Energy Corp. ("U.S. Energy", the "Company", "we" or "us"), is a Wyoming corporation organized in 1966. We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business activities are currently focused in South Texas and the Williston Basin in North Dakota. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We have historically explored for and produced oil and gas through a non-operator business model. As a non-operator, we rely on our operating partners to propose, permit, drill, complete and produce oil and gas wells. Before a well is drilled, the operator provides all oil and gas interest owners in the designated well the opportunity to participate in the drilling and completion costs and revenues of the well on a pro-rata basis. Our operating partners also produce, transport, market and account for all oil and gas production. We are currently developing our capability to operate properties, most notably with the appointment of David Veltri as President and Chief Operating Officer in December 2014. Mr. Veltri, who became our Chief Executive Officer in September 2015, has over 30 years of oil and gas operating experience.

We believe that additional value can be generated if we have the ability to operate oil and gas properties because operatorship will allow us to control drilling and production timing, capital costs and future planning of operations. We plan to look for opportunities to operate our own wells in the near future through acquisition of new oil and gas properties and/or by consolidating ownership in and around the areas in which we currently participate. We believe the current price climate will make opportunities available for us to acquire and/or develop operated properties, and our objective is to eventually operate the properties which comprise over 50% of our production.

Office Location and Website

Our principal executive office is located at 4643 S. Ulster Street, Suite 970, Denver, Colorado 80237, telephone (303) 993-3200.

Our website is www.usnrg.com. We make available on this website, through a direct link to the Securities and Exchange Commission's (the "SEC") website at http://www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and Forms 3, 4 and 5 relating to stock ownership of our directors, executive officers and significant shareholders. You may also find information related to our corporate governance, board committees and code of ethics on our website. Our website and the information contained on or connected to our website are not incorporated by reference herein and should not be considered part of this document. In addition, you may read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Oil and Gas Operations

We currently participate in oil and gas projects as a non-operating working interest owner through exploration and development agreements with various oil and gas exploration and production companies. Our working interest varies by project and may change over time based on the terms of our leases and operating agreements. These projects may result in numerous wells being drilled over the next three to five years depending on, among other things, commodity prices and the availability of capital resources required to fund the expenditures. We are also actively pursuing potential acquisitions of exploration, development and production-stage oil and gas properties or companies. Key attributes of our oil and gas properties include the following:

- Estimated proved reserves of 2,028,168 BOE (80% oil and 20% natural gas) as of December 31, 2015, with a standardized measure value of $17.8 million.
- As of March 21, 2016, our oil and gas leases covered 118,188 gross and 11,524 net acres.
- 150 gross (21.22 net) producing wells as of December 31, 2015 and as of March 21, 2016.
- 860 BOE per day average net production for 2015.

PV10 (defined in "Glossary of Oil and Gas Terms") is a non-GAAP measure that is widely used in the oil and gas industry and is considered by institutional investors and professional analysts when comparing companies. However, PV10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles the standardized measure of discounted future net cash flows to PV-10 as of December 31, 2015, 2014 and 2013:

	2015	2014	2013
Standardized measure of discounted net cash flows	$17,768	$81,889	$104,853
Plus discounted impact of future income tax expense	-	3,307	10,230
PV-10	$17,768	$85,196	$115,083

Additional information about our standardized measure and the changes during each of the last three years is included in Note 17 to our consolidated financial statements included in Item 8 of this report.

Activities with Operating Partners

The Company holds a geographically and geologically diverse portfolio of oil-weighted prospects in varying stages of exploration and development. Prospect stages range from prospect origination, including geologic and geophysical mapping, to leasing, exploratory drilling and development. The Company engages in the prospect stages either for its own account or with prospective partners to enlarge its oil and gas lease ownership base.

Each of the operators of our principal prospects has a substantial technical staff. We believe that these arrangements currently allow us to deliver value to our shareholders without having to build the full staff of geologists, engineers and land personnel required to work on diverse projects involving horizontal drilling in North Dakota and South Texas and conventional exploration in our Gulf Coast prospects. However, consistent with industry practice with smaller independent oil and gas companies, we also utilize specialized consultants with local expertise as needed. We anticipate that as we establish an operational center in an area, we will hire appropriate resources to supply critical aspects of the operations, such as drilling, completions and production.

Presented below is a description of key oil and gas projects with our operating partners:

Williston Basin, North Dakota (Bakken and Three Forks Formations)

Statoil ASA. On August 24, 2009, we entered into a Drilling Participation Agreement (the "DPA") with a wholly-owned subsidiary of Brigham Exploration Company ("Brigham") to jointly explore for oil and gas in up to 19,200 gross acres in a portion of Brigham's Rough Rider prospect in Williams and McKenzie Counties, North Dakota. Brigham was subsequently acquired by Statoil ASA. As part of the program we have participated in 26 wells and have proven up additional drilling locations depending on the successful development of the Three Forks Formation. These properties currently operated by Statoil comprise approximately 33% of the PV-10 related to our oil and gas reserves. Currently development has stopped due to the commodity price drop and high costs. We expect to develop the remaining acreage in the future when economics allow an acceptable return on capital.

The leases in the units are a combination of fee and state leases and all are held by production. In some areas, the rights may be depth limited to the Bakken and the upper part of the Three Fork formations under the terms of the leases obtained by Brigham from third parties, while other leases may have rights to all depths. Working interests earned vary according to Brigham's interest.

Zavanna, LLC. In December 2010, we signed two agreements with Zavanna LLC and other parties whereby we acquired 35% of Zavanna's working interests in oil and gas leases covering approximately 6,050 net acres in McKenzie County, North Dakota. The total net acres subject to the agreement has increased to 6,500 as a result of subsequent acquisitions from third parties. These properties currently comprise approximately 27% of our oil and gas reserves. The acquired acreage is in two prospects – the Yellowstone Prospect and the SE HR Prospect. We expect this program will ultimately result in 27 gross 1,280-acre spacing units with the potential for 108 gross Bakken and 108 gross Three Forks wells, based on an assumed four wells per formation in each spacing unit.

Effective December 2011, we sold an undivided 75% of our undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. and Yuma Exploration and Production Company, Inc. Under the terms of the agreement, we retained the remaining 25% interest in the undeveloped acreage and our original working interest in 10 completed wells in the SE HR and Yellowstone prospects. Our working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages. These properties operated by Zavanna currently comprise approximately 25% of the PV-10 related to our oil and gas reserves.

Texas and Louisiana (Gulf Coast)

Contango Oil and Gas Company (Eagle Ford Shale). In February 2011, we entered into a participation agreement with Crimson Exploration Inc. ("Crimson") to acquire a 30% working interest in an oil prospect and associated leases located in Zavala County, Texas (the "Leona River prospect"). Crimson was subsequently acquired by Contango Oil and Gas Company ("Contango"). Under the terms of the agreement, we earned a 30% working interest (22.5% net revenue interest) in approximately 4,675 gross contiguous acres (1,402 net mineral acres) through a combination of a cash payment and commitment well carry. All future drilling and leasing will be on a heads up basis with no carry by us. The prospect is an Eagle Ford shale oil window target in Zavala County, Texas. Two wells were drilled by Crimson to a total depth of approximately 12,500 feet (approximately 6,000 feet vertical and 6,500 feet horizontal) at the Leona River prospect. These producing wells hold the remaining development acreage.

In June 2011, we entered into a second participation agreement with Crimson to acquire an interest in an Eagle Ford oil prospect and associated leases located in Zavala and Dimmit Counties, Texas (the "Booth Tortuga prospect"). Under the terms of this second agreement with Crimson, we have acquired 30% of Crimson's working interest (approximately 22.5% net revenue interest) in approximately 7,186 gross acres (2,156 net).

Contango is currently the operator of the Leona River and Booth Tortuga prospects. All of the leases are currently held by production and comprise approximately 20% of the PV-10 related to our oil and gas reserves. Currently, our total acreage in the Leona River prospect and the Booth Tortuga prospect is approximately 11,861 gross acres (3,558 net). Based upon expected 120-acre spacing units, there is the potential for up to 98 gross and 30 net Eagle Ford drilling locations. Looking forward, we continue to seek additional leasing opportunities in the Eagle Ford oil window jointly with Crimson.

PetroQuest Energy, Inc. We have an interest in three natural gas and oil producing wells with PetroQuest Energy, Inc. ("PetroQuest") in Coastal Louisiana, with working interests of 11.9% (8.3% net revenue interest), 50.0% (36.0% net revenue interest) and 17.0% (12.75% net revenue interest). Two wells are currently shut-in. During January 2016, sole producing well averaged daily production of 838 MMCFD. Petro-Quest operates the wells. These properties operated by PetroQuest currently comprise approximately 7% of the PV-10 related to our oil and gas reserves.

Forward Plan

In 2016 and beyond, we intend to seek additional opportunities in the oil and gas sector, including but not limited to further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

Mining Activities

As discussed in Note 6 to the audited financial statement included in Item 8 of this report and *Management's Discussion and Analysis of Financial Condition and Results of Operations* included in Item 7 of this report, in February 2016 we disposed of our Mt. Emmons Project located near Crested Butte, Colorado rather than continuing our long-term development strategy. Accordingly, our mining assets and operations have been treated as discontinued operations as of December 31, 2015 and for all prior periods presented in our financial statements.

Item 1A - Risk Factors

The following risk factors should be carefully considered in evaluating the information in this Annual Report.

Risks Involving Our Business

The development of oil and gas properties involves substantial risks that may result in a total loss of investment.

The business of exploring for and developing natural gas and oil properties involves a high degree of business and financial risk, and thus a significant risk of loss of initial investment that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost and timing of drilling, completing and operating wells is often uncertain. Factors which can delay or prevent drilling or production, or otherwise impact expected results, include but are not limited to:

- unexpected drilling conditions;
- inability to obtain required permits from governmental authorities;
- inability to obtain, or limitations on, easements from land owners;
- uncertainty regarding our operating partners' drilling schedules;
- high pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution, spills and other environmental risks or accidents;
- changes in government regulations and issuance of local drilling restrictions or moratoria;
- adverse weather;
- reductions in commodity prices;
- pipeline ruptures; and
- unavailability or high cost of equipment, field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore that impair or prevent production. We may participate in wells that are or become unproductive or, though productive, do not produce in economic quantities. In addition, even commercial wells can produce less, or have higher costs, than we projected.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not necessarily indicative of future production rates.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities can adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves. We do not currently operate any of our properties, and therefore have limited ability to control the manner in which drilling and other exploration and development activities on our properties are conducted, which may increase these risks. Conversely, our anticipated transition to an operated business model entails risks as well. For example, the benefits of this transition may be less, or the costs may be greater, than we currently anticipate. In addition, we may be subject to a greater risk of drilling dry holes or encountering other operational problems until our operating capabilities are more fully developed. Similarly, we may incur liabilities as an operator that we have historically avoided through a non-operated business model.

Our business has been and may continue to be impacted by adverse commodity prices.

For the three years ended December 31, 2015, oil prices have ranged from highs over $100 per barrel in mid-2014 to recent lows below $30 per barrel. Global markets, in reaction to general economic conditions and perceived impacts of future global supply, have caused large fluctuations in price, and we believe significant future price swings are likely. Natural gas prices and NGL prices have experienced declines of comparable magnitude since mid-2014. Declines in the prices we receive for our oil and gas production have and may continue to adversely affect many aspects of our business, including our financial condition, revenues, results of operations, cash flows, liquidity, reserves, rate of growth and the carrying value of our oil and gas properties, all of which depend primarily or in part upon those prices. For example, due to recent significant decreases in the price of oil, we do not plan to participate in any material drilling activities until at least 2017. The reduction in drilling activity will likely result in lower production and, together with lower realized oil prices, lower revenue and EBITDAX. Declines in the prices we receive for our oil and gas can also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices can reduce the amount of oil and gas that we can produce economically and the estimated future cash flow from that production and, as a result, adversely affect the quantity and present value of our proved reserves. Among other things, a reduction in the amount or present value of our reserves can limit the capital available to us, as the maximum amount of available borrowing under our Credit Facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantity and value of the reserves.

The Williston Basin oil price differential could have adverse impacts on our revenue.

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). During 2015, our realized oil prices in the Williston Basin were approximately $8.00 per barrel less than West Texas Intermediate (“WTI”) quoted prices for crude oil. This discount, or differential, may widen in the future, which would reduce the price we receive for our production. We may also be adversely affected by widening differentials in other areas of operation.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to or higher than other areas where there is no price differential. This makes it more likely that a downturn in oil prices will result in a ceiling limitation write-down of our Williston Basin oil and gas properties. A widening of the differential would reduce the cash flow from our Williston Basin properties and adversely impact our ability to participate fully in drilling with Statoil, Zavanna and other operators and to effect our strategy of transitioning to an operated business model. Our production in other areas could also be affected by adverse changes in differentials. In addition, changes in differentials could make it more difficult for us to effectively hedge our exposure to changes in commodity prices.

The agreement governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

The debt agreement between our wholly-owned subsidiary, Energy One LLC, and Wells Fargo Bank, N.A. contains restrictive covenants that limit Energy One’s ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including covenants that require the (i) interest coverage ratio (EBITDAX to interest expense) to exceed 3.0 to 1.0; (ii) total debt to EBITDAX ratio to be less than 3.5 to 1; and (iii) the current ratio to exceed 1.0 to 1.0, each as defined in the Credit Facility. Our failure to comply with these covenants in the future could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient capital resources to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. Adverse commodity prices and reduced drilling activity may result in continuing breaches of the covenants in the Credit Facility.

Additionally, the Credit Facility restricts Energy One’s ability to incur additional debt, pay cash dividends and other restricted payments, sell assets, enter into transactions with affiliates, and to merge or consolidate with another company. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

We require funding for our working capital deficit and debt obligations. We may be unable to obtain such funding, particularly as we are in continuing breach of covenants in the Credit Facility.

Our working capital at December 31, 2015 was negative $9.8 million which is primarily the result of classifying $6.0 million of borrowings under the Credit Facility as a current liability. Even though this debt does not mature until July 2017, we have been unable to comply with the debt covenants during the last three quarters of 2015 and we project continuing non-compliance in 2016. While Wells Fargo has provided waivers for our non-compliance through December 31, 2015, there is no assurance that it will continue to do so in the future. In addition, the borrowing base under the Credit Facility is subject to redetermination periodically and from time to time in the lenders' discretion. Borrowing base reductions may occur as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the Credit Facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Currently, we do not have adequate funding to repay Wells Fargo if it declares our covenant non-compliance to be an event of default or if it elects to reduce the borrowing base below the amount of the outstanding balance.

Regardless of our ability to comply with the covenants under the Credit Facility, we will pursue alternative funding sources before the facility matures in July 2017. Other sources of external debt or equity financing may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Also, the issuance of equity may be dilutive to existing shareholders. During 2016, we will attempt to obtain a larger credit facility that will enable the repayment of amounts outstanding under the Credit Facility and provide capital resources to participate in acquisition and development activities; obtaining additional financing is an important objective for us in 2016 and may be critical in our efforts to continue to operate and to avoid bankruptcy, liquidation or similar proceedings. We cannot provide any assurance that we will be successful in this regard.

Our industry partners may elect to engage in drilling activities that we are unwilling or unable to participate in during 2016. Our exploration and development agreements contain customary industry non-consent provisions. Pursuant to these provisions, if a well is proposed to be drilled or completed but a working interest owner elects not to participate, the resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 150% to 300% of the capital they provided to cover the non-participant’s share. In order to be in position to avoid non-consent penalties and to make opportunistic investments in new assets, we will continue to evaluate various options to obtain additional capital, including additional debt financing, sales of one or more producing or non-producing oil and gas assets and the issuance of shares of our common stock.

The oil and gas business presents the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. For example, initial results from one or more of the oil and gas programs could be marginal but warrant investing in more wells. Dry holes, over-budget exploration costs, low commodity prices, or any combination of these or other adverse factors, could result in production revenues below projections, thus adversely impacting cash expected to be available for continued work in a program, and a reduction in cash available for investment in other programs. These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and could also mandate obtaining new capital. There can be no assurance that we will be able to complete any financing transaction on acceptable terms.

Competition may limit our opportunities in the oil and gas business.

The oil and gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They also may be willing and able to pay more for oil and gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. In addition, there is substantial competition in the oil and gas industry for investment capital, and we may not be able to compete successfully in raising additional capital if needed.

Successful exploitation of the Buda formation, the Williston Basin (Bakken and Three Forks shales) and the Eagle Ford shale is subject to risks related to horizontal drilling and completion techniques.

Operations in the Buda formation and the Bakken, Three Forks and Eagle Ford shales in many cases involve utilizing the latest drilling and completion techniques in an effort to generate the highest possible cumulative recoveries and therefore generate the highest possible returns. Risks that are encountered while drilling include, but are not limited to, landing the well bore in the desired drilling zone, staying in the zone while drilling horizontally through the shale formation, running casing the entire length of the well bore (as applicable to the formation) and being able to run tools and other equipment consistently through the horizontal well bore.

For wells that are hydraulically fractured, completion risks include, but are not limited to, being able to fracture stimulate the planned number of frac stages, and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these latest drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficient period of time.

Currently, the typical cost for drilling and completing a horizontal well is estimated at approximately $3.0 million to $4.0 million for wells targeting the Buda formation, $6.5 million to $7.5 million for wells in the Williston Basin, and $6.5 million for wells in the Eagle Ford, in each case on a gross basis. Costs for any individual well will vary due to a variety of factors. These wells are significantly more expensive than a typical onshore shallow conventional well. Accordingly, unsuccessful exploration or development activity affecting even a small number of wells could have a significant impact on our results of operations. Costs other than drilling and completion costs can also be significant for Williston Basin, Eagle Ford and other wells. For example, we incurred approximately $3.1 million in workover costs relating to a single Williston Basin well in 2011, and these costs substantially exceeded our estimates.

If our access to oil and gas markets is restricted, it could negatively impact our production and revenues. Securing access to takeaway capacity may be particularly difficult in less developed areas of the Williston Basin.

Market conditions or limited availability of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and other midstream facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, rail transportation and processing facilities owned and operated by third parties. In particular, access to adequate gathering systems or pipeline or rail takeaway capacity is limited in the Williston Basin. In order to secure takeaway capacity and related services, we or our operating partners may be forced to enter into arrangements that are not as favorable to operators as those in other areas.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. Without successful drilling or acquisition activities, our reserves and production will decline over time. In addition, competition for crude oil and gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary to evaluate and integrate acquisitions that are substantially greater than those available to us.

As part of our growth strategy, we have made and may continue to make acquisitions. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources than we do. In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price for the acquisition, future crude oil, natural gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation, and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited. If we are unable to integrate acquisitions successfully and realize anticipated economic, operational and other benefits in a timely manner, substantial costs and delays or other operational, technical or financial problems could result.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to participate in all or even a substantial portion of the many locations we have potentially available through our agreements with our partners. The extent of our participation will depend on drilling and completion results, commodity prices, the availability and cost of capital relative to ongoing revenue from completed wells, applicable spacing rules and other factors. Significant recent declines in the price of oil may reduce the number of potential locations that we will ultimately drill.

Lower oil and gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting to account for our oil and gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop these properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a “ceiling limit” that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs exceed the ceiling limit, we must charge the amount of the excess to earnings (a charge referred to as a “ceiling test write-down”). The risk of a ceiling test write-down increases when oil and gas prices are depressed, if we have substantial downward revisions in estimated proved reserves or if we drill unproductive wells.

Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost, except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depreciation, depletion and amortization are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of (a) unamortized cost reduced by the related net deferred tax liability and asset retirement obligations, and (b) the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated costs, adjusted for contract provisions, any financial derivatives that hedge our oil and gas revenue and asset retirement obligations, and unescalated oil and gas prices during the period, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, less (iv) income tax effects related to tax assets directly attributable to the natural gas and crude oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

We perform a quarterly ceiling test for our only oil and gas cost center, which is the United States. During each of the quarters in 2015, capitalized costs for oil and gas properties exceeded the ceiling and we recorded aggregate ceiling test write-downs of $57.7 million primarily due to a decline in the prices of oil and gas. The ceiling test incorporates assumptions regarding pricing and discount rates over which we have no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2015, we used a weighted average price applicable to our properties of $43.54 per barrel for oil and $3.36 per Mcfe for natural gas to compute the future cash flows of each of the producing properties at that date. Based on lower oil prices during the first quarter of 2016, we expect to recognize an additional ceiling test write-down between $3.0 and $4.0 million during the first quarter of 2016.

Capitalized costs associated with unevaluated properties include exploratory wells in progress, costs for seismic analysis of exploratory drilling locations, and leasehold costs related to unproved properties. Unevaluated properties not subject to depreciation, depletion and amortization amounted to an aggregate of $5.7 million as of December 31, 2015. These costs will be transferred to evaluated properties to the extent that we subsequently determine the properties are impaired or if proved reserves are established.

We do not currently serve as operator for any of our oil and gas properties. Many of our joint operating agreements contain provisions that may be subject to legal interpretation, including allocation of non-consent interests, complex payout calculations that impact the timing of reversionary interests, and the impact of joint interest audits.

Substantially all of our oil and gas interests are subject to joint operating and similar agreements. Some of these agreements include payment provisions that are complex and subject to different interpretations and/or can be erroneously applied in particular situations. In the past, we received significant overpayments due to an operator's failure to timely recognize the payout implications of our joint operating agreements. The operator has elected to withhold the net revenues from all of our wells that it operates to recover these overpayments, decreasing cash flows that would otherwise be available to operate our business.

We believe certain operators have failed to allocate our share of non-consent ownership interests which results in contingent liabilities to the extent we have not been billed for our proportionate share of such interests, and contingent assets to the extent that we have not received our share of the net revenues. We record net contingent liabilities for the obligations that we believe are probable. Additionally, we believe an operator has failed to allocate our share of certain royalty interests that we are entitled to under a participation agreement. The ultimate resolution of these uncertainties about our working interests and net revenue interests can extend over a long period of time and we can incur substantial amounts of legal fees to resolve disputes with the operators of our properties.

Joint interest audits are a normal process in our business to ensure that operators adhere to standard industry practices in the billing of costs and expenses related to our oil and gas properties. However, the ultimate resolution of joint interest audits can extend over a long period of time in which we attempt to recover excessive amounts charged by the operator. Joint interest audits result in incremental costs for the audit services and we can incur substantial amounts of legal fees to resolve disputes with the operators of our properties.

We do not currently operate our drilling locations. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of these non-operated assets.

We do not currently operate any of the prospects we hold with industry partners. As a non-operator, our ability to exercise influence over the operations of the drilling programs is limited. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interests, but we disagree with the proposal and do not (or are unable to) participate, we will forfeit our share of revenues from the well until the participants receive 150% to 300% of their investment. In some cases, we could lose all of our interest in the well. We would avoid a penalty of this kind only if a majority of the working interest owners agree with us and the proposal does not proceed.

The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- the nature and timing of the operator’s drilling and other activities;

- the timing and amount of required capital expenditures;
- the operator’s geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator’s selection of suitable technology.

The fact that our industry partners serve as operator makes it more difficult for us to predict future production, cash flows and liquidity needs. Our ability to grow our production and reserves depends on decisions by our partners to drill wells in which we have an interest, and they may elect to reduce or suspend the drilling of those wells.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

Oil and gas reserve reports are prepared by independent consultants to provide estimates of the quantities of hydrocarbons that can be economically recovered from proved properties, utilizing commodity prices for a trailing 12-month period and taking into account expected capital, operating and other expenditures. These reports also provide estimates of the future net present value of the reserves, which we use for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this report represent estimates only. Estimating quantities of, and future cash flows from, proved oil and gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future production costs; ad valorem, severance and excise taxes; availability of capital; estimates of required capital expenditures, workover and remedial costs; and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of the reserves, the economically recoverable quantities of oil and gas attributable to the properties, the classifications of reserves based on risk of recovery, and estimates of our future net cash flows.

At December 31, 2015, 78% of our estimated proved reserves were producing, 1% were proved developed non-producing and 21% were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenue from estimated proved developed non-producing and proved undeveloped reserves will not be realized until sometime in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and gas reserves. The timing and success of the production and the expenses related to the development of oil and gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV-10 and standardized measure estimates are based on costs as of the date of the estimates and assume fixed commodity prices. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate. If actual prices as of December 31, 2015 were used to derive the estimated quantity and present value of our reserves, those estimates would have been significantly lower than those included in this report, which are based on a 12-month average price under applicable SEC rules.

Further, the use of a 10% discount factor to calculate PV10 and standardized measure values may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and gas industry in general are subject.

The use of derivative arrangements in oil and gas production could result in financial losses or reduce income.

From time to time, we use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil production. The fair value of our derivative instruments is marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instruments is recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for the relevant period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with our risk management strategies.

In addition, depending on the type of derivative arrangements we enter into, the agreements could limit the benefit we would receive from increases in oil prices. It cannot be assumed that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in commodity prices.

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through regulations that are in the process of being implemented by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Dodd-Frank Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and gas properties and other assets, would likely make it impracticable to implement our current hedging strategy. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, the loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our potential drilling locations are identified, the leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. The risk that our leases may expire will generally increase when commodity prices fall, as lower prices may cause our operating partners to reduce the number of wells they drill. In addition, on certain portions of our acreage, third-party leases could become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

Our producing properties are primarily located in the Williston Basin and South Texas, making us vulnerable to risks associated with having operations concentrated in these geographic areas.

Because our operations are geographically concentrated in the Williston Basin and South Texas (91% of our production in 2015 was from these areas), the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, regulatory issues, natural disasters and fluctuations in the prices of crude oil and gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and other transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. Any of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. In addition, our operations in the Williston Basin may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify competition for services, infrastructure and equipment during months when drilling is possible and may result in periodic shortages. Any of these risks could have a material adverse effect on our financial condition and results of operations.

Insurance may be insufficient to cover future liabilities.

Our business is currently focused on oil and gas exploration and development and we also have potential exposure to general liability and property damage associated with the ownership of other corporate assets. In the past, we relied primarily on the operators of our oil and gas properties to obtain and maintain liability insurance for our working interest in our oil and gas properties. In some cases, we may continue to rely on those operators' insurance coverage policies depending on the coverage. Since 2011 we have obtained our own insurance policies for our oil and gas operations that are broader in scope and coverage and are in our control. We also maintain insurance policies for liabilities associated with and damage to general corporate assets.

We also have separate policies for environmental exposures related to our prior ownership of the water treatment plant operations related to our discontinued mining operations. These policies provide coverage for remediation events adversely impacting the environment. See "Insurance" below.

We would be liable for claims in excess of coverage and for any deductible provided for in the relevant policy. If uncovered liabilities are substantial, payment could adversely impact the Company's cash on hand, resulting in possible curtailment of operations. Moreover, some liabilities are not insurable at a reasonable cost or at all.

Oil and gas operations are subject to environmental and other regulations that can materially adversely affect the timing and cost of operations.

Oil and gas exploration, development and production activities are subject to certain federal, state and local laws and regulations relating to a variety of issues, including environmental quality and pollution control. These laws and regulations increase costs and may prevent or delay the commencement or continuance of operations. Specifically, the industry generally is subject to regulations regarding the acquisition of permits before drilling, well construction, the spacing of wells, unitization and pooling of properties, habitat and endangered species protection, reclamation and remediation, restrictions on drilling activities in restricted areas, emissions into the environment, management of drilling wastes, water discharges, chemical disclosures and storage and disposition of solid and hazardous wastes. In addition, state laws require wells and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of any future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Under these laws and regulations, we could be liable for personal injuries, property and natural resource damages, releases or discharges of hazardous materials, well reclamation costs, oil spill clean-up costs, other remediation and clean-up costs, plugging and abandonment costs, governmental sanctions, and other environmental damages. Some environmental laws, such as the federal Water Pollution Control Act (the “Clean Water Act”) and the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), impose joint and several and strict liability. Strict liability means liability without fault such 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 otherwise without negligence on our part. If exposed to joint and several liability, we could be responsible for more than our share of a particular clean-up, reclamation or other obligation, and potentially for the entire obligation, even where other parties are subject to liability for the same obligation. These third parties may include prior operators of properties we have acquired, operators of properties in which we have an interest and parties that provide transportation services for us.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a common practice in the oil and gas industry used to stimulate the production of oil, natural gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and gas properties, including our resource plays in the Eagle Ford shale of south Texas and the Bakken/Three Forks formations in North Dakota. Hydraulic fracturing involves injecting water, sand and certain chemicals under pressure to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities, as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act (the "SDWA"), and has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA announced plans to update its chloride water quality criteria for the protection of aquatic life under the Clean Water Act. Flowback and produced water from the hydraulic fracturing process contain total dissolved solids, including chlorides, and regulation of these fluids could be affected by the new criteria. The EPA has delayed issuing a draft criteria document until 2016. The EPA has also announced that it will develop pre-treatment standards for disposal of wastewater produced from shale gas operations through publicly owned treatment works. The regulations will be developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. On April 7, 2015, the EPA published a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process in the Federal Register. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to publicly owned treatment facilities. The public comment period for the proposed rule ended on July 17, 2015. If the EPA implements further regulations of hydraulic fracturing, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

The state of Texas has adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, several municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

Several federal governmental agencies are actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. On June 4, 2015, the EPA issued a draft assessment of potential impacts to drinking water resources from hydraulic fracturing. The draft report did not find widespread impacts to drinking water from hydraulic fracturing. The EPA's inspector general released a report on July 16, 2015 recommending increased EPA oversight of permit issuances as well as the chemicals used in hydraulic fracturing. The United States Department of Energy is also actively involved in research on hydraulic fracturing practices, including groundwater protection.

On March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands, including private surface lands with underlying federal minerals. The rule was scheduled to become effective on June 24, 2015, but was temporarily stayed by a federal court. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in hydraulic fracturing operations meet certain construction standards, development of appropriate plans for managing flowback water that returns to the surface, heightened standards for interim storage of recovered waste fluids, and submission of detailed information to the BLM regarding the geology, depth and location of pre-existing wells. Several states, tribes, and industry groups filed several pending lawsuits challenging the rule and the BLM's authority to regulate hydraulic fracturing. In February 2016 the U.S. District Court in Wyoming issued a preliminary injunction staying implantation of BLM's hydraulic fracturing regulations. BLM has appealed the preliminary injunction to the Tenth Circuit Court of Appeals. The outcome of this litigation is uncertain. If the rule becomes effective, we expect to incur additional costs to comply with such requirements that may be significant in nature, and we could experience delays or even curtailment in the pursuit of hydraulic fracturing activities in certain wells. The rule could also affect drilling units that include both private and federal mineral resources.

Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. If hydraulic fracturing becomes regulated at the federal level, our fracturing activities could become subject to additional permit or disclosure requirements, associated permitting delays, operational restrictions, litigation risk, and potential cost increases. Additionally, certain members of Congress have called upon the United States 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 United States 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. The United States Geological Survey Offices of Energy Resources Program, Water Resources and Natural Hazards and Environmental Health Offices also have ongoing research projects on hydraulic fracturing. These ongoing studies, depending on their course and outcomes, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory processes.

Further, on August 16, 2012, the EPA issued final rules subjecting all new and modified oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and all existing and new operations to the National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards require the use of reduced emission completion ("REC") techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line beginning in January 2015. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAP include maximum achievable control technology ("MACT") standards for those glycol dehydrators and certain storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. These rules will require additional control equipment, changes to procedure, and extensive monitoring and reporting. The EPA stated in January 2013, however, that it intends to reconsider portions of the final rule. On September 23, 2013, the EPA published new standards for storage tanks subject to the NSPS. In December 2014, the EPA finalized additional updates to the 2012 NSPS. The amendments clarified stages for flowback and the point at which green completion equipment is required and updated requirements for storage tanks and leak detection requirements for processing plants. The EPA has stated that it continues to review other issues raised in petitions for reconsideration.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standard ("NAAQS") for ozone under the federal Clean Air Act to a range within 65-70 ppb. On October 1, 2015, EPA finalized a rule that lowered the standard to 70 ppb. This lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and gas operations in ozone nonattainment areas likely would be subject to more stringent emission controls, emission offset requirements for new sources, and increased permitting delays and costs. This could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the TSCA rulemaking.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. Over the past few years, several court cases have addressed aspects of hydraulic fracturing. In a case that could delay operations on public lands, a court in California held that the BLM did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. Courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for, and production of, oil, natural gas, and associated liquids, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state, or local laws, or the implementation of new regulations, regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

Requirements to reduce gas flaring could have an adverse effect on our operations.

Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering and processing network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission, North Dakota’s chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. The Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. In addition, the BLM has recently proposed standards for reducing venting and flaring on public lands, which is part of a series of steps by the Obama 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. These capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of crude oil, natural gas, and NGLs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of crude oil, natural gas, and NGLs.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Certain federal income tax deductions currently available with respect to crude oil and gas and exploration and development may be eliminated as a result of future legislation.

President Obama has made proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations. In addition, the President has proposed a $10.25 per barrel tax on oil that, if imposed, would have similarly adverse effects on us.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs

In December 2009, the EPA made a finding that emissions of carbon dioxide, methane, and other “greenhouse gases” endanger public health and the environment because emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes. Based on this finding, the EPA has adopted and implemented a comprehensive suite of regulations to restrict and otherwise regulate emissions of greenhouse gases under existing provisions of the CAA. In particular, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA. One rule requires a reduction in greenhouse gas emissions from motor vehicles, and the other regulates permitting and greenhouse gas emissions from certain large stationary sources. These EPA regulatory actions have been challenged by various industry groups, initially in the D.C. Circuit, which in 2012 ruled in favor of the EPA in all respects. However, in June 2014, the United States Supreme Court reversed the D.C. Circuit and struck down the EPA's greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. As a result of that ruling, large sources of air pollutants other than greenhouse gases would still be required to implement the best available capture technology for greenhouse gases. The EPA has also adopted reporting rules for greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries as well as certain onshore oil and gas extraction and production facilities.

Several other kinds of cases on greenhouse gases have been heard by the courts in recent years. While courts have generally declined to assign direct liability for climate change to large sources of greenhouse gas emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant greenhouse gas emissions, and new claims for damages and increased government scrutiny will likely continue. Such cases often seek to challenge air emissions permits that greenhouse gas emitters apply for, seek to force emitters to reduce their emissions, or seek damages for alleged climate change impacts to the environment, people, and property. Any court rulings, laws or regulations that restrict or require reduced emissions of greenhouse gases could lead to increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce.

The United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas “cap and trade” programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. The Congressional Budget Office provided Congress with a study on the potential effects on the United States economy of a tax on greenhouse gas emissions. While “carbon tax” legislation has been introduced in the Senate, the prospects for passage of such legislation are highly uncertain at this time.

On June 25, 2013, President Obama outlined plans to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations as well as pipelines and coal mines (the “Climate Plan”). The President’s Climate Plan, along with recent regulatory initiatives and ongoing litigation filed by states and environmental groups, signal a new focus on methane emissions, which could pose substantial regulatory risk to our operations. In March 2014, President Obama released a strategy to reduce methane emissions, which directed the EPA to consider additional regulations to reduce methane emissions from the oil and gas sector. On January 14, 2015, the Obama Administration announced additional steps to reduce methane emissions from the oil and gas sector by 40 to 45 percent by 2025. These actions include a commitment from the EPA to issue new source performance standards for methane emissions from the oil and gas sector. Pursuant to this commitment, in September 2015, the EPA proposed emission standards for methane and VOC for sources in the oil and gas sector constructed or modified after September 1, 2015. The proposed rules expand the 2012 NSPS for VOC emissions from the oil and gas sector to include methane emissions. For sources not affected by the 2012 NSPS, the proposed rule imposes both VOC and methane standards. In particular, the proposal would require methane reductions from centrifugal and reciprocating compressors, pneumatic pumps, fugitive emissions from well sites and compressor stations and equipment leaks at natural gas processing plants. The proposal does not extend to existing sources and EPA has not indicated when it will propose existing source standards. Additionally, in January 2016, the BLM proposed additional rules designed to reduce methane venting and flaring from production wells, pneumatic controllers and storage tanks on federal and tribal lands, which are expected to be finalized in 2016. The focus on legislating methane also could eventually result in:

- Requirements for methane emission reductions from existing oil and gas equipment;
- increased scrutiny for sources emitting high levels of methane, including during permitting processes;
- analysis, regulation and reduction of methane emissions as a requirement for project approval; and
- actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors.

In relation to the Climate Plan, both assumed Global Warming Potential (“GWP”) and assumed social costs associated with methane and other greenhouse gas emissions have been finalized, including a 20% increase in the GWP of methane. Changes to these measurement tools could adversely impact permitting requirements, application of agencies’ existing regulations for source categories with high methane emissions, and determinations of whether a source qualifies for regulation under the CAA.

Finally, it should be noted that certain studies have suggested that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. President Obama's Climate Plan emphasizes preparation for such events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such events. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Williston Basin and the Gulf Coast can be adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and gas activities sometimes cannot be conducted as effectively during the winter months, and this can materially increase our operating and capital costs. Gulf Coast operations are also subject to the risk of adverse weather events, including hurricanes.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with oil and gas prices and activity levels in new regions, causing periodic shortages. These problems can be particularly severe in certain regions such as the Williston Basin and Texas. During periods of high oil and gas prices, the demand for drilling rigs and equipment tends to increase along with increased activity levels, and this may result in shortages of equipment. Higher oil and gas prices generally stimulate increased demand for equipment and services and subsequently often result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in exploration, production and midstream operations. These types of shortages and subsequent price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those activities that we currently have planned and budgeted, causing us to miss our forecasts and projections.

We depend on key personnel.

Our sole employee has experience in dealing with the acquisition of and financing of oil and gas properties. We rely extensively on third party consultants for accounting, legal, professional engineering, geophysical and geological advice in oil and gas matters. The loss of key personnel could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel.

Risks Related to Our Stock

We have issued shares of Series A Preferred Stock with rights superior to those of our common stock.

Our articles of incorporation authorize the issuance of up to 100,000 shares of preferred stock, $0.01 par value. Shares of preferred stock may be issued with such dividend, liquidation, voting and conversion features as may be determined by the Board of Directors without shareholder approval. Pursuant to this authority, in February 2016 we approved the designation of 50,000 shares of Series A Convertible Preferred Stock ("Series A Preferred") in connection with the disposition of our mining segment.

The Series A Preferred accrues dividends at a rate of 12.25% per annum of the Adjusted Liquidation Preference; such dividends are not payable in cash but are accrued and compounded quarterly in arrears. The "Adjusted Liquidation Preference" is initially $40 per share of Series A Preferred for an aggregate of $2.0 million, with increases each quarter by the accrued quarterly dividend. The Series A Preferred is senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution will be declared or paid on our common stock, (i) unless approved by the holders of Series A Preferred and (ii) unless and until a like dividend has been declared and paid on the Series A Preferred on an as-converted basis.

At the option of the holder, each share of Series A Preferred may initially be converted into 80 shares of our common stock (the "Conversion Rate") for an aggregate of 4,000,000 shares. The Conversion Rate is subject to anti-dilution adjustments for stock splits, stock dividends and certain reorganization events and to price-based anti-dilution protections. Each share of Series A Preferred will be convertible into a number of shares of common stock equal to the ratio of the initial conversion value to the conversion value as adjusted for accumulated dividends multiplied by the Conversion Rate. In no event will the aggregate number of shares of common stock issued upon conversion be greater than 4,760,095 shares. The Series A Preferred will generally not vote with our common stock on an as-converted basis on matters put before our shareholders. The holders of the Series A Preferred have the right to require us to repurchase the Series A Preferred in connection with a change of control. The dividend, liquidation and other rights provided to holders of the Series A Preferred will make it more difficult for holders of common stock to realize value from their investment.

Future equity transactions and exercises of outstanding options or warrants could result in dilution.

From time to time, we have sold common stock, warrants, convertible preferred stock and convertible debt to investors in private placements and public offerings. These transactions caused dilution to existing shareholders. Also, from time to time, we issue options and warrants to employees, directors and third parties as incentives, with exercise prices equal to the market price at the date of issuance. During 2015, we also granted shares of restricted common stock that are subject to issuance upon future vesting events. Vesting of restricted common stock and exercise of options and warrants would result in dilution to existing shareholders. Future issuances of equity securities, or securities convertible into equity securities, would also have a dilutive effect on existing shareholders. In addition, the perception that such issuances may occur could adversely affect the market price of our common stock.

We do not intend to declare dividends on our common stock.

We do not intend to declare dividends on our common stock in the foreseeable future. Under the terms of our Series A Preferred Stock, we are prohibited from paying dividends on our common stock without the approval of the holders of the Series A Preferred Stock. Accordingly, our common shareholders must look solely to increases in the price of our common stock to realize a gain on their investment, and this may not occur.

We could implement take-over defense mechanisms that could discourage some advantageous transactions.

Although our shareholder rights plan expired in 2011, certain provisions of our governing documents and applicable law could have anti-takeover effects. For example, we are subject to a number of provisions of the Wyoming Management Stability Act, an anti-takeover statute, and have a classified or "staggered" board. We could implement additional anti-takeover defenses in the future. These existing or future defenses could prevent or discourage a potential transaction in which shareholders would receive a takeover price in excess of then-current market values, even if a majority of the shareholders support such a transaction.

Our stock price likely will continue to be volatile.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2015, our common stock has traded as high as $5.00 per share and as low as $0.12 per share. We expect our common stock will continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- price volatility in the oil and gas commodities markets;
- variations in our drilling, recompletion and operating activity;
- relatively small amounts of our common stock trading on any given day;
- additions or departures of key personnel;
- legislative and regulatory changes; and
- changes in the national and global economic outlook.

The stock market has recently experienced significant price and volume fluctuations, and oil and gas prices have declined significantly. These fluctuations have particularly affected the market prices of securities of oil and gas companies like ours.

If our common stock is delisted from the NASDAQ Capital Market, its liquidity and value could be reduced.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market®, the common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). If the closing bid price of the common stock is below $1.00 for 30 consecutive trading days, then the closing bid price of the common stock must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. On July 9, 2015, the closing bid price of our common stock had been below $1.00 for 30 consecutive trading days, starting the 180-day grace period to regain compliance with the rule. On July 10, 2015, we received a letter from The Nasdaq Stock Market indicating that for 30 consecutive business days the common stock had not maintained a minimum closing bid price of $1.00 per share as required by Nasdaq Listing Rule 5550(a)(2). Accordingly, the grace period provided by the rule has commenced. We cannot guarantee that we will be able to regain compliance with the minimum price requirement within the grace period or satisfy other continued listing requirements. If our common stock is delisted from trading on the NASDAQ Capital Market, it may be eligible for trading over the counter, but the delisting of our common stock from NASDAQ could adversely impact the liquidity and value of our common stock.

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and gas

The following table sets forth our net proved reserves as of the dates indicated. We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our independent reserve engineers. Reserve estimates are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2015, 2014 and 2013 are based on the following average prices, in each case as adjusted for transportation, quality, and basis differentials applicable to our properties on a weighted average basis:

	2015	2014	2013
Oil (per Bbl)	$43.54	$85.63	$91.06
Gas (per Mcfe)	$3.36	$8.84	$6.41

Presented below is a summary of our proved oil and gas reserve quantities as of the end of each of our last three fiscal years:

	As of December 31, **2015** [1]			**2014** [2]			**2013** [2]		
	Oil (Bbl)	Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Gas (Mcfe)	Total (BOE)
Proved developed	1,248,750	2,068,190	1,593,448	1,754,668	1,892,446	2,070,076	1,875,528	1,701,282	2,159,075
Proved undeveloped	366,430	409,740	434,720	2,365,069	1,318,801	2,584,869	1,584,187	670,628	1,695,958
Total proved reserves	1,615,180	2,477,930	2,028,168	4,119,737	3,211,247	4,654,945	3,459,715	2,371,910	3,855,033

(1) Our reserve estimates as of December 31, 2015 are based on the reserve report prepared by Jane E. Trusty, PE. Ms. Trusty is an independent petroleum engineer and a State of Texas Licensed Professional Engineer (License

#60812). The reserve estimates provided by Ms. Trusty were based upon her review of the production histories and other geological, economic, ownership and engineering data, as provided by us or as obtained from the operators of our properties. A copy of Ms. Trusty's report is filed as an exhibit to this report.

(2) Our reserve estimates as of December 31, 2014 and 2013 are based on reserve reports prepared by Cawley, Gillespie & Associates, Inc., or CGA. CGA is a nationally recognized independent petroleum engineering firm and is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Senior Vice President and a State of Texas Licensed Professional Engineer (License #83462). The reserve estimates were based upon the review by CGA of the production histories and other geological, economic, ownership and engineering data, as provided by us or as obtained from the operators of our properties. A copy of CGA's December 31, 2014 and 2013 reports were previously filed as exhibits to our 2014 and 2013 Annual Reports on Form 10-K, respectively.

As of December 31, 2015, our proved reserves totaled 2,028,168 BOE, of which approximately 79% were classified as proved developed and 21% were classified as proved undeveloped. On a BOE basis, approximately 80% of the total is derived from 1,615,180 Bbls of oil and 20% is derived from 2,477,930 Mcf of natural gas. See the "Glossary of Oil and Gas Terms" for an explanation of these and other terms.

You should not place undue reliance on estimates of proved reserves. See *"Risk Factors - Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves"*. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

We believe we maintain an effective system of internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information is assessed for validity when meetings are held with management, land personnel and third party operators to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field 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 the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Our reserve database is currently maintained by Jane Trusty, PE. Ms. Trusty works with our personnel to review field performance, future development plans, current revenues and expense information. Following these reviews, the reserve database and supporting data is updated so that Ms. Trusty can prepare her independent reserve estimates and final report.

Proved Undeveloped Reserves. As of December 31, 2015, our proved undeveloped reserves totaled 434,720 BOE. On a BOE basis, approximately 84% of the total is derived from 366,430 Bbls of oil and 16% is derived from 409,740 Mcf of natural gas. On a BOE basis, during 2015 our proved undeveloped reserves decreased by 2,150,149 BOE compared with 2,584,869 BOE of proved undeveloped reserves as of December 31, 2014. This decrease was primarily due to a 49% reduction in oil prices used for the 2015 report as compared to the 2014 report. Lower oil prices have resulted in a dramatic reduction in drilling activity during 2015 and this slowdown has resulted in increased competition among drilling and completion services companies and lower drilling and completion costs. In addition, there has been an overall longer term trend of lower drilling and completion costs; since 2012, drilling and completion costs for horizontal wells on our properties in the Williston Basin have dropped from approximately $11.5 million to a range of approximately $6.5 to $7.5 million. Our development plan contemplates an increase in Bakken drilling after 2016 assuming that the outlook improves for higher oil prices.

As of December 31, 2015, we have no proved undeveloped reserves that have been included in this category for more than five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. As a result of the low oil price environment in 2015, we did not incur any capital expenditures to convert our proved undeveloped reserves to producing status and we do not intend to incur capital expenditures for this purpose in 2016. As of December 31, 2015, our estimated future development costs relating to proved undeveloped reserves are approximately $8.1 million, all of which is expected to be incurred in 2017 and 2018. Only two well locations with proved undeveloped reserves are scheduled for development more than five years after the date such reserves were initially classified as proved undeveloped, and the PV-10 for these two locations is approximately $40,000. These locations are continuing to be classified as proved undeveloped reserves due to environmental and regulatory restrictions related to the proximity to navigable waterways in North Dakota requires additional time to resolve.

Oil and Gas Production, Production Prices, and Production Costs. The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and gas for the years ended December 31, 2015, 2014 and 2013.

	2015	2014	2013
Production Volume			
Oil (Bbls)	221,650	329,828	343,719
Natural gas (Mcfe)	553,505	813,081	487,282
BOE	313,901	465,342	424,933
Daily Average Production Volume			
Oil (Bbls per day)	607	904	942
Natural gas (Mcfe per day)	1,516	2,228	1,119
BOE per day	860	1,275	1,164
Net prices realized			
Oil per Bbl	$40.82	$85.89	$90.81
Natural gas per Mcfe	2.26	4.98	4.66
Oil and natural gas per BOE	32.80	69.58	79.18
Operating Expenses per BOE			
Production costs	$23.42	$22.86	$24.64
Depletion, depreciation and amortization	26.80	31.56	32.06

We encourage you to read this information in conjunction with the information contained in our financial statements and related notes included in Item 8 of this report.

The following table provides a regional summary of our production for the years ended December 31, 2015, 2014 and 2013:

	2015 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2014 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2013 Oil (Bbl)	Gas (Mcfe)	Total (BOE)
Williston Basin (North Dakota)	163,380	151,191	188,579	212,052	198,375	245,115	280,789	203,510	314,707
Eagle Ford / Buda (South Texas)	53,149	232,094	91,831	110,413	437,130	183,268	53,603	85,750	67,895
Austin Chalk (South Texas)	4,860	4,190	5,558	6,627	5,191	7,492	7,717	6,967	8,878
Gulf Coast (Louisiana and Texas)	261	166,030	27,933	736	172,379	29,466	1,610	191,055	33,453
Total	221,650	553,505	313,901	329,828	813,075	465,341	343,719	487,282	424,933

Drilling and Other Exploratory and Development Activities. The following table sets forth information with respect to development and exploratory wells we drilled during each of the three years in the period ended December 31, 2015.

	2015 Gross	Net	2014 Gross	Net	2013 Gross	Net
Development wells:						
Productive	13.0	0.5	14.0	1.6	15.0	1.3
Non-productive	-	-	-	-	-	-
Sub-total	13.0	0.5	14.0	1.6	15.0	1.3
Exploratory wells:						
Productive	1.0	0.3	21.0	2.7	15.0	0.9
Non-productive	-	-	-	-	1.0	0.2
Sub-total	1.0	0.3	21.0	2.7	16.0	1.1
Total	14.0	0.8	35.0	4.3	31.0	2.4

The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and gas that may ultimately be recovered. See *"Management's Discussion and Analysis of Financial Condition and Results of Operation – General Overview."*

Oil and Gas Properties, Wells, Operations and Acreage. The following table summarizes information about our gross and net productive wells as of December 31, 2015.

	Gross Producing Wells			Net Producing Wells			Average Working Interest		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
North Dakota	109	-	109	10.69	-	10.69	9.8 %	0.0 %	9.8 %
Texas	39	-	39	10.15	-	10.15	26.0 %	0.0 %	26.0 %
Louisiana	-	2	2	-	0.39	0.39	0.0 %	19.4 %	19.4 %
Total	148	2	150	20.84	0.39	21.23	14.1 %	19.4 %	14.1 %

For purposes of the above table, a well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion. As of December 31, 2015, none of the wells in the above table contain multiple completions.

The following map reflects where our oil and gas properties are generally located:

Acreage. The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2015.

	Developed		Undeveloped		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Williston Basin (North Dakota):						
Rough Rider Prospect	19,200	1,175	-	-	19,200	1,175
Yellowstone and SEHR Prospects	35,840	1,225	-	-	35,840	1,225
ASEN North Dakota Acquisition	16,320	114	-	-	16,320	114
East Texas and Louisiana:	1,824	289	-	-	1,824	289
Buda/Eagle Ford/Austin Chalk (Texas):						
Leona River Prospect	3,765	1,130	-	-	3,765	1,130
Booth Tortuga Prospect	12,013	3,050	-	-	12,013	3,050
Big Wells Prospect	240	36	4,003	600	4,243	636
Carrizo Creek and South McKnight Prospects	640	213	1,994	126	2,634	339
Total	89,842	7,232	5,997	726	95,839	7,958

As a non-operator, we are subject to lease expiration if the operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or a “savings clause” is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have commenced. While we generally expect to test or establish production from most of our acreage prior to expiration of the applicable lease terms, there is no assurance that we can or will do so. As of December 31, 2015, all of our acreage in the Williston Basin and Louisiana is held by production. For our properties in Texas, the approximate expiration of our gross and net acres are set forth below:

	Texas (1)	
Year Ending December 31,	Gross	Net
2016	1,600	285
2017	761	203

	2,361	488

(1) Includes acreage located in the Buda, Eagle Ford, and Austin Chalk areas of South Texas.

Present Activities. As of April 11, 2016, no wells were being drilled and no wells were pending completion.

Real Estate

We own a 14-acre tract in Riverton, Wyoming, with a two-story 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor was formerly occupied by the Company. We are currently attempting to secure tenants for the vacant portion of this building but we are also considering an outright sale of the property.

In addition, we own three city lots covering 13.84 acres adjacent to our corporate office building in Fremont County, Wyoming. We intend to sell these properties without development. However, there can be no assurance that sales of any of these properties will be completed on the terms, or in the time frame, we expect or at all.

Uranium

Anfield Resources. In 2007, we sold all of our uranium assets for cash and stock of the purchaser, Uranium One Inc. (“Uranium One”). The assets sold included a uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, we were entitled to additional consideration from Uranium One up to $40.0 million based on the performance of the mill, achievement of commercial production and royalties, but no additional consideration was ever received from Uranium One. In August 2014, we entered into an agreement with Anfield Resources Inc. (“Anfield”) whereby if Anfield was successful in acquiring the property from Uranium One, we agreed to release Anfield from the future payment obligations stemming from our 2007 sale to Uranium One. On September 1, 2015, Anfield acquired the property from Uranium One and is now obligated to provide the following consideration to us:

- Issuance of $2.5 million in Anfield common shares to us. The Anfield shares are to be held in escrow and released in tranches over a 36-month period. Pursuant to the agreement, if any of the share issuances result in the Company holding in excess of 20% of the then issued and outstanding shares of Anfield (the “Threshold”), such shares in excess of the Threshold would not be issued at that time, but deferred to the next scheduled share issuance. If, upon the final scheduled share issuance the number of shares to be issued exceeds the Threshold, the value in excess of the Threshold is payable to us in cash,
- $2.5 million payable in cash upon 18 months of continuous commercial production, and
- $2.5 million payable in cash upon 36 months of continuous commercial production.

The first tranche of common shares resulted in the issuance of 7,436,505 shares of Anfield with a market value of $750,000 and such shares were delivered to us in September 2015. Since shares of Anfield are thinly traded, we determined that the market value of Anfield did not reflect trading on an “orderly market”. Instead, a net present value technique was used to determine the fair value for Anfield shares of approximately $238,000. The timing of any future receipt of cash from Anfield is not determinable and there can be no assurance that any cash will ever be received from Anfield or that the shares received from Anfield will ever be liquidated for cash.

Royalty on Uranium Claims. We hold a 4% net profits interest on certain unpatented mining claims on Rio Tinto’s Jackpot uranium property located on Green Mountain in Wyoming. To date, we have not received any payments related to this royalty and there can be no assurance that any amount will ever be received.

Research and Development

No research and development expenditures have been incurred, either on the Company’s account or sponsored by a customer of the Company, during the past three fiscal years.

Marketing, Major Customers and Delivery Commitments

Markets for oil and gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is marketed by our industry partners for our benefit and is sold to competing buyers, including large oil refining companies and independent marketers. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. We had no material delivery commitments as of December 31, 2015.

Competition

The oil and gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and gas. Our competitors principally consist of major and intermediate sized integrated oil and gas companies, independent oil and gas companies and individual producers and operators. In particular, we compete for property acquisitions and our operating partners compete for the equipment and labor required to operate and develop our properties. Our competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Environmental

Like the oil and gas industry in general, our properties are subject to extensive and changing federal, state and local laws and regulations designed to protect and preserve natural resources and the environment. The long-term and recent trends in environmental legislation and regulation generally are toward stricter standards, and this is likely to continue. These laws and regulations often require a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands. Federal, state and local laws and regulations regarding the discharge of materials into the environment or otherwise relating to the protection of the environment include the National Environmental Policy Act ("NEPA"), the Clean Air Act, the Clean Water Act, the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act ("*RCRA*"), and CERCLA. Regulations and permit requirements applicable to our operations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect. See "*Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays*" and "*Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs"*" in "Risk Factors" for a discussion of certain regulatory developments that may have an adverse effect on us.

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to regulation under RCRA and comparable state statutes, although certain mining and oil and gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. EPA has limited the disposal options for certain wastes that are designated as hazardous wastes. Moreover, certain wastes generated by our oil and gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes and, as a result, become subject to more rigorous and costly management, disposal and remediation requirements.

Although all of our currently producing oil and gas properties are currently operated by third parties, the activities on the properties are still subject to environmental protection regulations that affect us. Operators are required to obtain drilling permits, restrict substances that can be released into the environment, and require remedial work to mitigate pollution from our operations, close and cover disposal pits, and plug abandoned wells. Violations by the operator could result in substantial liabilities for which we could be responsible. Based on the current regulatory environment in those states in which we have oil and gas investments and rules and regulations currently in effect, we do not currently expect to make any material capital expenditures for environmental control facilities.

Oil and gas operations also are subject to various federal, state and local regulations governing oil and gas production and state limits on allowable rates of production by well. These regulations may affect the amount of oil and gas available for sale, the availability of adequate pipeline and other regulated transportation and processing facilities, and other matters. State and federal regulations generally are intended to prevent waste of oil and gas, protect groundwater resources, protect rights to produce oil and gas between owners in a common reservoir, control the amount produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. From time to time, regulatory agencies and legislative bodies make various proposals to change existing requirements or to add new requirements. Regulatory changes can adversely impact the permitting and exploration and development of mineral and oil and gas properties including the availability of capital.

Wells in the Bakken and Three Forks formations in North Dakota produce natural gas as well as crude oil. Constraints in the current gas gathering network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. The North Dakota Industrial Commission, the State's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In addition, the Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals.

In addition, oil and gas projects are subject to extensive permitting requirements. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

Insurance

The following summarizes the material aspects of the Company's insurance coverage:

General

We have liability insurance coverage in amounts we deem sufficient for our business operations, consisting of property loss insurance on all major assets equal to the approximate replacement value of the assets and additional liability and control of well insurance for our oil and gas drilling programs. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in curtailment of projected future operations.

Mt. Emmons Project

The Company was responsible for all costs to operate the water treatment plant at the Mt. Emmons Project until the disposition of this property in February 2016. During 2016, we continue to maintain $10 million of coverage for environmental impairment liability.

Employees

As of December 31, 2015, we had 1 full-time employee and we utilized several consultants on an as needed basis.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2015 and developments in those proceedings through March 21, 2016 are summarized below.

Water Court Proceeding

As previously disclosed, we have been involved in an action in Colorado Water Court concerning the conditional water rights associated with the Mt. Emmons Project. As discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments*, in February 2016, we transferred our Mt. Emmons Project to Mt. Emmons Mining Company and as a result of this transfer, we no longer have a material interest in this Water Court proceeding.

Statoil ASA

In June 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended royalty funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Brigham was subsequently sold to Statoil ASA ("Statoil") who assumed Brigham's rights and obligations under this case. The Company owns a working interest, not royalty interest, in this well so no funds have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. Our legal position is aligned with Statoil, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

Reformed Assignments

We are also a party to litigation that seeks to reform certain assignments of mineral interests we acquired from Brigham. This matter involves the depth below the surface to which the assignments were effective. The plaintiff is seeking to reform the agreement such that our assignment would be revised to be 12 feet closer to the surface. This dispute affects one of our producing wells.

Quiet Title Action – Willerson Lease

In September 2013, we acquired from Chesapeake Exploration, LLC ("Chesapeake") a 15% working interest in approximately 4,244 gross mineral acres in Dimmit County, Texas, that are leased from Dr. Darrell Willerson and affiliates ("Willerson"). In January 2014, Willerson inquired if their lease had terminated due to the failure to achieve production in paying quantities pursuant to the terms of the lease. Along with Crimson Exploration Operating, Inc. and Liberty Energy, LLC, we filed a declaratory judgment action in the District Court of Dimmit County in May 2014 seeking a determination from the court that the lease remains valid and in effect. Willerson counterclaimed for breach of contract, trespass, and related causes of action. In January 2016, Willerson filed a third-party petition alleging breach of contract, trespass, and related causes of action against Chesapeake and EXCO Operating Company, LP.

Arbitration of Employment Claim

A former employee has claimed that we owe up to $1.8 million under an Executive Severance and Non-Compete Agreement (the "Agreement") due a change of control and termination of employment without cause. The Agreement requires that any disputes be submitted to binding arbitration and a request for arbitration was submitted by the former employee in March 2016. We do not believe there is any merit to the claims of termination without cause or that a change of control occurred. A date has not yet been established for the arbitration proceedings.

Item 4 – Mine Safety Disclosures.

Not applicable.

PART II

Item 5 - Market for Registrant’s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

Market Information

Our common stock is traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market. Quarterly high and low sale prices follow:

	Low	High
Year ended December 31, 2014:		
First quarter	$3.39	$4.97
Second quarter	3.94	5.00
Third quarter	3.19	4.42
Fourth quarter	1.17	2.95
Year ended December 31, 2015:		
First quarter	$1.13	$1.66
Second quarter	0.53	1.37
Third quarter	0.36	0.71
Fourth quarter	0.12	0.51

As of April 11, 2016, the closing market price was $0.37 per share.

Holders

As of April 11, 2016, there were approximately 880 shareholders of record, and we had 28,233,068 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2015 and 2014 and do not intend to declare any cash dividends in the foreseeable future. Our ability to pay dividends in the future is subject to limitations under state law and the terms of the Credit Facility, which restricts the ability of Energy One to pay dividends to the Company. Our ability to pay dividends on our common stock is also limited by the terms of our Series A Convertible Preferred Stock issued in February 2015. See *Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments.*

Issuance of Securities in 2015

During 2015, we issued a total of 152,074 shares of common stock to three officers of the Company pursuant to restricted stock grants under our 2012 Equity and Performance Incentive Plan. As a condition of severance agreements entered into with the officers during the third and fourth quarters of 2015, vesting was accelerated which resulted in the issuance of 152,074 shares of our common stock. Except as previously disclosed in a Current Report on Form 8-K, we did not sell any equity securities in 2015 in transactions not registered under the Securities Act.

Stock Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock for the five years ended December 31, 2015, to that of the cumulative return on a $100 investment in the S&P 500, the NASDAQ Market Index, and the S&P Small Cap 600 Energy Index. The indices are included for comparative purposes only.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS

This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date the Annual Report was filed and irrespective of any general incorporation language in any such filing.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data as of the dates and periods indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(Dollars in Thousands, Except Per Share Amounts)				
Revenue from oil and gas sales	$10,296	$32,379	$33,647	$32,534	$30,958
Operating expenses:					
Oil and gas production costs	7,352	10,638	10,469	10,788	11,552
Depreciation, depletion and amortization	8,412	14,685	13,623	14,893	13,997
Impairment of oil and gas properties	57,676	-	5,828	5,189	-
General and administrative:					
Stock-based compensation	948	527	384	345	1,241
Other	4,972	5,909	5,018	8,764	7,020
Total operating expenses	79,360	31,759	35,322	39,979	33,810
Operating income (loss)	(69,064)	620	(1,675)	(7,445)	(2,852)
Non-operating income (expense):					
Gain (loss) on oil price risk derivatives	1,559	582	(1,075)	1,091	(848)
Other income (expense), net	484	200	(1,336)	(39)	457
Interest expense	(263)	(385)	(429)	(203)	(326)
Income (loss) before income taxes and discontinued operations	(67,284)	1,017	(4,515)	(6,596)	(3,569)
Income tax benefit	-	-	-	44	3,755
Income (loss) from continuing operations	(67,284)	1,017	(4,515)	(6,552)	186
Discontinued operations:					
Discontinued operations	(2,992)	(3,108)	(2,744)	(2,802)	(1,930)
Impairment loss	(22,620)	-	(120)	(1,891)	(3,063)
Loss from discontinued operations	(25,612)	(3,108)	(2,864)	(4,693)	(4,993)
Net loss	$(92,896)	$(2,091)	$(7,379)	$(11,245)	$(4,807)
Earnings (loss) per share- basic					
Continuing operations	$(2.40)	$0.04	$(0.16)	$(0.24)	$0.01
Discontinued operations	(0.91)	(0.12)	(0.11)	(0.17)	(0.19)
Total	$(3.31)	$(0.08)	$(0.27)	$(0.41)	$(0.18)

Earnings (loss) per share- diluted					
Continuing operations	$(2.40)	$0.04	$(0.16)	$(0.24)	$0.01
Discontinued operations	(0.91)	(0.11)	(0.11)	(0.17)	(0.19)
Total	$(3.31)	$(0.07)	$(0.27)	$(0.41)	$(0.18)
Weighted average shares outstanding					
Basic	28,065,000	27,833,000	27,679,000	27,467,000	27,239,000
Diluted	28,065,000	28,099,000	27,678,698	27,467,000	27,239,000

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(Dollars in Thousands, Except Financial Results Per BOE Amounts)				
Oil and gas production quantity (BOE)	313,901	465,342	424,933	444,702	442,360
Financial results per BOE:					
Realized oil and gas sales price	$32.80	$69.58	$79.18	$73.16	$69.98
Oil and gas production costs	(23.42)	(22.86)	(24.64)	(24.26)	(26.11)
Depletion, depreciation and amortization	(26.80)	(31.56)	(32.06)	(33.49)	(31.64)
General and administrative expense	(18.86)	(13.83)	(12.71)	(20.48)	(18.67)
Cash flow data					
Net cash provided by (used in):					
Operating activities	$2,504	$23,737	$20,143	$16,038	$4,931
Investing activities	(565)	(19,542)	(18,219)	(20,877)	(17,908)
Financing activities	(154)	(3,055)	(10,821)	(2,433)	21,558
Discontinued operations	(2,441)	(2,985)	11,927	(2,777)	(1,519)
Balance sheet and reserve data (at end of year)					
Working capital (deficit)	$(9,778)	$(654)	$5,970	$12,762	$16,199
Oil and gas properties, using full cost method	23,432	88,269	86,922	85,634	90,942
Total assets	33,132	123,523	126,801	140,827	162,439
Long-term debt, less current portion	-	6,000	9,000	10,000	12,200
Total shareholders' equity	15,475	107,395	109,057	116,117	126,781
Reserve data (at end of year)					
Total proved oil and gas reserves (BOE)	2,028,168	4,654,944	3,855,031	2,913,324	3,195,324
Proved developed oil and gas reserves (BOE)	1,593,448	2,070,076	2,159,075	2,007,375	2,214,665

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion includes forward-looking statements. Please refer to *Cautionary Information about Forward-Looking Statements* on pages 3 and 4 of this report for important information about these types of statements. Additionally, please refer to the *Glossary of Oil and Gas Terms* on pages 5 and 6 of this report for oil and gas industry terminology used herein.

General Overview

We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business is currently focused in South Texas and the Williston Basin in North Dakota. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We currently explore for and produce oil and gas through a non-operator business model; however, we may operate oil and gas properties for our own account and may expand our holdings or operations into other areas. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is drilled, the operator is required to provide all oil and gas interest owners in the designated well the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production. As discussed in Item 1. Business, our long-term strategic focus is to develop operational capabilities through the pursuit of opportunities to acquire operated properties and/or operatorship of existing properties.

Recent Developments

In February 2016, we transferred to Mt. Emmons Mining Company, a subsidiary of Freeport-McMoRan Inc. ("MEM"), our Mt. Emmons mine site located in Gunnison County, Colorado, including the Keystone Mine, a related water treatment plant (the "WTP") and other related properties (collectively, the "Purchased Assets"). MEM replaced the Company as the permittee and owner of the WTP and will discharge the obligation of the Company to operate the WTP in accordance with the applicable permits issued by the Colorado Department of Public Health and Environment.

As additional consideration for MEM to accept transfer of the Purchased Assets, including related obligations, the Company entered into a Series A Convertible Preferred Stock Purchase Agreement (the “Series A Purchase Agreement”) with MEM pursuant to which the Company issued to MEM 50,000 shares of newly designated Series A Convertible Preferred Stock (the “Preferred Stock”). The Preferred Stock accrues dividends at a rate of 12.250% per annum of the Adjusted Liquidation Preference (as defined), which are not payable in cash but are accrued and compounded quarterly in arrears. The “Adjusted Liquidation Preference” is initially $40 per share of Preferred Stock, increased each quarter by the accrued quarterly dividend. The Preferred Stock is senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution will be declared or paid on junior stock, including the Company’s common stock, (1) unless approved by the holders of Preferred Stock, voting as a group and (2) unless and until a like dividend has been declared and paid on the Preferred Stock on an as-converted basis, unless waived by the holders of Preferred Stock.

Each share of Preferred Stock may initially be converted into 80 shares of the common stock of the Company at the option of the holder at any time. The conversion rate is subject to anti-dilution adjustments for stock splits, stock dividends and certain reorganization events and to price-based anti-dilution protections. Each share of Preferred Stock will be convertible into a number of shares of Common Stock equal to the product of (1) the conversion value as adjusted for accumulated dividends divided by the initial conversion value, multiplied by (2) the conversion rate (plus cash in lieu of fractional shares and dividends accrued since the last accrual date). The Preferred Stock will generally not vote with the common stock on an as-converted basis on matters put before the Company’s shareholders. The holders of the Preferred Stock have the right to approve specified matters and have the right to require the Company to repurchase the Preferred Stock in connection with a change of control.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States (“GAAP”) requires us to make 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 and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions. A summary of our significant accounting policies is detailed in *Note 1 – Organization, Operations and Significant Accounting Polices* in Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and Gas Reserve Estimates. Our estimates of proved reserves are based on quantities of oil and gas reserves which current engineering data indicates are recoverable from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are critical estimates in determining our depreciation, depletion and amortization expense (“DD&A”) and our full cost ceiling limitation (“Full Cost Ceiling”). Future cash inflows are determined by applying oil and gas prices, as adjusted for transportation, quality and basis differentials to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Future production and development costs are based on costs existing at the effective date of the report. Expected cash flows are discounted to present value using a prescribed discount rate of 10% per annum.

Estimates of proved reserves are inherently imprecise because of uncertainties in projecting rates of production and timing of developmental expenditures, interpretations of geological, geophysical, engineering and production data and the quality and quantity of available data. Changing economic conditions also may affect our estimates of proved reserves due to changes in developmental costs and changes in commodity prices that may impact reservoir economics. We utilize independent reserve engineers to estimate our proved reserves at the end of each fiscal quarter during the year.

Oil and Gas Properties. We follow the full cost method in accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center are amortized using the equivalent unit-of-production method, based on proved oil and gas reserves. The capitalized costs are amortized over the life of the reserves associated with the assets, with the DD&A recognized in the period that the reserves are produced. DD&A is calculated by dividing the period’s production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our DD&A per unit. Costs associated with production and general corporate activities are expensed in the period incurred.

Exploratory wells in progress are excluded from the DD&A calculation until the outcome of the well is determined. Similarly, unproved property costs are initially excluded from the DD&A calculation. Unproved property costs not subject to the DD&A calculation consist primarily of leasehold and seismic costs related to unproved areas. Unproved property costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved oil and gas properties are assessed quarterly for impairment to determine whether we are still actively pursuing the project and whether the project has been proven either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated DD&A and net of deferred income taxes may not exceed the Full Cost Ceiling. The Full Cost Ceiling is equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the unimpaired cost of unproved properties not subject to amortization, plus the lower of cost or fair value of unproved properties that are subject to amortization. When net capitalized costs exceed the Full Cost Ceiling, impairment is recognized.

Derivative Instruments. We use derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. We offset fair value amounts recognized for derivative instruments executed with the same counterparty. Although we do not designate any of our derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on oil price risk derivatives in our consolidated statements of operations.

Our Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties. The master contracts with approved counterparties identify the CEO as the Company representative authorized to execute trades.

Discontinued Operations- Mining Properties. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations. Effective January 1, 2015, we adopted new accounting guidance related to the recognition and presentation of discontinued operations in our financial statements. Under the revised guidance, beginning in 2015 only disposals of businesses that represent strategic shifts that have a major effect on our operations and financial results are reported in discontinued operations. Accordingly, the disposal of our mining segment qualified for reporting as discontinued operations.

We capitalized all costs incidental to the acquisition of mining properties and related equipment. The costs of operating a related water treatment plant on the mine property, holding costs to maintain permits, mining exploration costs and general corporate overhead were expensed as incurred. As of December 31, 2015, we recognized impairment of the carrying value of the mine property when we determined that the carrying value could not be recovered.

Joint Interest Operations. We do not serve as operator for any of our oil and gas properties. Therefore, we rely to a large extent on the operator of the property to provide us with timely and accurate information about the operations of the properties. Joint interest billings from the operators serve as our primary source of information to record revenue, operating expenses and capital expenditures for our properties on a monthly basis. Many of our properties are subject to complex participation and operating agreements where our working interests and net revenue interests are subject to change upon the occurrence of certain events, such as the achievement of “payout”. These calculations may be subject to error and differences of interpretation which can cause uncertainties about the proper amount that should be recorded in our accounting records. When these issues arise, we make every effort to work with the operators to resolve the issues promptly.

Revenue Recognition. We record oil and gas revenue under the sales method of accounting. Under the sales method, we recognize revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which we are entitled based on our interest in the properties. Gas balancing obligations as of December 31, 2015 and 2014 were not significant.

Stock Based Compensation. We measure the cost of employee services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date. We recognize the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. For awards granted which contain a graded vesting schedule, and the only condition for vesting is a service condition, compensation cost is recognized as an expense on a straight-line basis over the requisite service period as if the award was, in substance, a single award.

Recently Issued Accounting Standards

Please refer to the section entitled *Recent Accounting Pronouncements* under *Note 1 – Organization, Operations and Significant Accounting Policies* in Item 8 of this report for additional information on recently issued accounting standards and our plans for adoption of those standards.

Results of Operations

Comparison of our Statements of Operations for the Years Ended December 31, 2015 and 2014

During the year ended December 31, 2015, we recorded a net loss of $92.9 million as compared to a net loss of $2.1 million for the year ended December 31, 2014. Our loss from continuing operations was $67.3 million for the year ended December 31, 2015 compared to income from continuing operations of $1.0 million for the year ended December 31, 2014. In the following sections we discuss our revenue, operating expenses, non-operating income, and discontinued operations for the year ended December 31, 2015 compared to the year ended December 31, 2014.

Revenue. Presented below is a comparison of our oil and gas sales, production quantities and average sales prices for the years ended December 31, 2015 and 2014 (dollars in thousands, except average sales prices):

	2015	2014	Change Amount	Percent
Revenue:				
Oil	$9,047	$28,331	$(19,284)	-68 %
Gas	1,249	4,048	(2,799)	-69 %
Total	$10,296	$32,379	$(22,083)	-68 %
Production quantities:				
Oil (Bbls)	221,650	329,828	(108,178)	-33 %
Gas (Mcfe)	553,505	813,081	(259,576)	-32 %
BOE	313,901	465,342	(151,441)	-33 %
Average sales prices:				
Oil (Bbls)	$40.82	$85.89	$(45.07)	-52 %
Gas (Mcfe)	2.26	4.98	(2.72)	-55 %
BOE	32.80	69.58	(36.78)	-53 %

The decrease in our oil sales of $19.3 million for the year ended December 31, 2015 resulted from a 33% reduction in our oil production and a 52% reduction in the average oil price realized during 2015 compared to 2014. The decrease in our gas sales of $2.8 million for the year ended December 31, 2015, was driven by a 32% decrease in our gas production and a 55% reduction in the average gas price realized during 2015 compared to 2014. The reduction in our net realized oil and gas prices is reflective of the dramatic decrease in global commodity prices during 2015 as compared to 2014. During 2015, the differential between West Texas Intermediate (“WTI”) quoted prices for crude oil and the prices we realize for sales in the Williston Basin was approximately $8.00 per barrel lower. We expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices from this region.

For the year ended December 31, 2015, we produced 313,901 BOE, or an average of 860 BOE per day, as compared to 465,342 BOE or 1,275 BOE per day in 2014. Production for our Williston Basin properties decreased by 56,535 BOE during 2015, which is a 23% reduction compared to 2014. This decrease of 23% is consistent with the decrease in Williston Basin production during 2014 as a result of normal production declines and lower working interests for wells that have achieved payout. Production for our Eagle Ford and Buda properties in South Texas decreased by 91,437 BOE during 2015, which is a 50% reduction compared to 2014. This reduction was attributable to the normal decline in production for wells in this area and we did not participate in further drilling in this area during 2015.

Oil and Gas Production Costs. Presented below is a comparison of our oil and gas production costs for the years ended December 31, 2015 and 2014 (dollars in thousands):

	2015	2014	Change Amount	Percent
Production taxes	$1,021	$2,758	$(1,737)	-63 %
Lease operating expense	6,331	7,880	(1,549)	-20 %
Total	$7,352	$10,638	$(3,286)	-31 %

For the year ended December 31, 2015, production taxes decreased by $1.7 million compared to 2014. Approximately $1.9 million of the decrease in production taxes resulted from lower oil and gas sales; this decrease was partially offset by higher tax rates in 2015 which accounted for an increase in production taxes of $0.2 million. For the year ended December 31, 2015, lease operating expense decreased by $1.5 million which was primarily due to the implementation of cost reduction strategies by the operators of our wells. During 2016, we expect further well by well reductions as cost reductions programs continue during the industry downturn.

Depreciation, depletion and amortization. Our DD&A rate for the year ended December 31, 2015 was $26.80 per BOE compared to $31.56 per BOE for 2014. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves. The primary factor that resulted in a reduction in our DD&A rate for the year ended December 31, 2015 was quarterly impairment charges that resulted from our quarterly Full Cost Ceiling limitations. During each of the four quarters in 2015, we recognized impairment charges which reduced the net capitalized costs subject to future DD&A calculations. Accordingly, our DD&A rate per BOE decreased during 2015 as we reduced the net capitalized costs by the quarterly impairment charges discussed below.

Impairment of oil and gas properties. During the year ended December 31, 2014, the Company did not recognize any oil and gas impairment expense. During the year ended December 31, 2015, we recorded impairment charges related to our oil and gas properties of $57.7 million because the net capitalized costs were in excess of the Full Cost Ceiling limitation. These quarterly impairment charges were primarily due to the deepening declines in the price of oil during 2015. Presented below are the weighted average prices (before applying the impact of basis differentials between the benchmark prices and the actual prices realized for our wells) used to prepare our reserve estimates and to calculate our Full Cost Ceiling limitations for each of the four quarters in 2015, along with the impairment charges recognized during each of the four quarters in 2015 (dollars in thousands, except average prices):

	Average Price		
	Oil (Bbl)	Gas (MMbtu)	Impairment Charge
First quarter	$82.72	$ 3.88	$ 19,240
Second quarter	71.68	3.39	3,208
Third quarter	59.21	3.06	21,446
Fourth quarter	50.28	2.59	13,782
Total impairment			$ 57,676

Our quarterly reserve reports are prepared based on a trailing 12-month average for benchmark oil and gas prices; therefore, the weighted average oil price used to prepare our reserve estimates and to calculate our Full Cost Ceiling limitation for the first quarter of 2016 is expected to decline from $50.28 to approximately $46.00 (both before further deduction for basis differentials). Assuming other variables remain substantially unchanged, we expect to record an impairment charge in the range of $3.0 million to $4.0 million during the first quarter of 2016.

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2015 and 2014 (dollars in thousands):

	2015	2014	Change Amount	Percent
Compensation and benefits, including directors	$2,602	$4,124	$(1,522)	-37 %
Stock-based compensation	948	527	421	80 %
Employee severance costs	504	-	504	n/a
Professional fees, insurance and other	1,866	1,785	81	5 %
Total	$5,920	$6,436	$(516)	-8 %

General and administrative expenses decreased by $0.5 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. This decrease was attributable to a reduction of $1.5 million in compensation and benefits, which was driven by (i) a decrease in executive retirement expense of $0.6 million since the actuarial calculations indicated the retirement plan was fully funded in 2015, (ii) a decrease in compensation and benefits of $0.6 million related to the retirement of two executive officers for all or part of 2015, (iii) a decrease in employee bonuses of $0.2 million, and (iv) a decrease in board of directors' compensation of $0.1 million. Other significant changes in general and administrative expenses included (i) an increase in stock-based compensation which primarily resulted from the acceleration of vesting of stock options and restricted stock associated with employees who terminated employment in 2015, and (ii) an increase in severance expense of $0.5 million which was comprised of $0.4 million for 3 executive officers and $0.1 million for 6 other employees who terminated employment by the end of 2015.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2015 and 2014 (dollars in thousands):

	2015	2014	Change Amount	Percent
Realized gain (loss) on oil price risk derivatives	$(75)	$316	$(391)	-124 %
Unrealized gain (loss) on oil price risk derivatives	1,634	266	1,368	514 %
Gain on sale of assets	121	112	9	8 %
Loss on investments	(68)	-	(68)	n/a
Rental and other income	431	88	343	390 %
Interest expense	(263)	(385)	122	-32 %
Total	$1,780	$397	$1,383	348 %

We recognized a realized loss on oil price risk derivatives of $0.1 million for the year ended December 31, 2014 compared to a gain of $0.3 million for 2014. We recognized an unrealized gain on oil price risk derivatives of $1.6 million for the year ended December 31, 2014 compared to a gain of $0.3 million for 2013. The realized and unrealized gain for 2015 was $1.6 million compared to a realized gain of $0.6 million for 2014, an improvement of $1.0 million which is indicative of the decline in the market for crude oil after we entered into the derivative contracts.

During each of the years ended December 31, 2015 and 2014, we recorded a gain on the sale of assets of $0.1 million, which resulted from the sale of non-oil and gas related property and equipment. During the year ended December 31, 2015, we determined that our marketable equity securities had experienced an other than temporary impairment in value which resulted in an unrealized loss of $0.1 million.

Interest expense decreased by $0.1 million during the year ended December 31, 2015 compared to 2014. This decrease was primarily attributable to a reduction in our weighted average borrowing for 2015.

Discontinued Operations. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations for all periods presented in this report. As of December 31, 2015, we recognized an impairment charge of $22.6 million when we determined that the carrying value could not be recovered. During the years ended December 31, 2015 and 2014, the costs of operating our water treatment plant on the mine property, holding costs to maintain permits, and general corporate overhead associated with the mine property were expensed as incurred. The total operating and holding expenses amounted to $3.0 million for the year ended December 31, 2015 compared to $3.1 million for 2014.

Comparison of our Statements of Operations for the Years Ended December 31, 2014 and 2013

During the year ended December 31, 2014, we recorded a net loss of $2.1 million as compared to a net loss of $7.4 million for the year ended December 31, 2013. Our income from continuing operations was $1.0 million for the year ended December 31, 2014 compared to a loss from continuing operations of $4.5 million for the year ended December 31, 2013. In the following sections we discuss our revenue, operating expenses, non-operating income, and discontinued operations for the year ended December 31, 2014 compared to the year ended December 31, 2013.

Revenue. Presented below is a comparison of our oil and gas sales, production quantities and average sales prices for the years ended December 31, 2014 and 2013 (dollars in thousands, except average sales prices):

	2014	2013	Change Amount	Percent
Revenue:				
Oil	$28,331	$31,214	$(2,883)	-9 %
Gas	4,048	2,433	1,615	66 %
Total	$32,379	$33,647	$(1,268)	-4 %
Production quantities:				
Oil (Bbls)	329,828	343,719	(13,891)	-4 %
Gas (Mcfe)	813,081	487,282	325,799	67 %
BOE	465,342	424,933	40,409	10 %
Average sales prices:				
Oil (Bbls)	$85.89	$90.81	$(4.92)	-5 %
Gas (Mcfe)	4.98	4.99	(0.01)	0 %
BOE	69.58	79.18	(9.60)	-12 %

The increase in our gas sales of $1.6 million for the year ended December 31, 2014, was driven by a 67% increase in our gas production which reflected a 214% increase in our production of NGLs during 2014. This impact of higher production was partially offset by a 4% reduction in the average gas price realized during 2014 compared to 2013. The decrease in our oil sales of $2.9 million for the year ended December 31, 2014 resulted from a 4% reduction in our oil production and a 5% reduction in the average oil price realized during 2014 compared to 2013. The differential between WTI quoted prices for crude oil and the prices we realized for sales in the Williston Basin ranged from $13.00 to $21.00 per barrel during 2014. For the year ended December 31, 2014, we produced 465,342 BOE, or an average of 1,275 BOE per day, as compared to 424,933 BOE or 1,164 BOE per day in 2013. In our South Texas region, production increased 148% from 76,773 BOE in 2013 to 190,760 BOE in 2014 as a result of our Buda limestone drilling program. Production in our Bakken region decreased 22%, from 314,707 BOE in 2013 to 245,115 BOE in 2014 as a result of normal production declines and lower working interests in wells drilled in this region.

Oil and Gas Production Costs. Presented below is a comparison of our oil and gas production costs for the years ended December 31, 2014 and 2013 (dollars in thousands):

	2014	2013	Change Amount	Percent
Production taxes	$2,758	$3,339	$(581)	-17 %
Lease operating expense	7,880	7,130	750	11 %
Total	$10,638	$10,469	$169	2 %

For the year ended December 31, 2014, production taxes decreased by $0.6 million as a result of the reduction in oil and gas sales and lower tax rates in 2014 compared to 2013. For the year ended December 31, 2014, lease operating expense increased by $0.8 million due to an increase in the number of producing wells and an increase in workover expense of $0.2 million in 2014 as compared to 2013.

Depreciation, depletion and amortization. Our DD&A rate for the year ended December 31, 2014 was $31.56 per BOE compared to $32.06 per BOE for 2013. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Impairment of oil and gas properties. During the year ended December 31, 2013, we recorded impairment of $5.8 million since the net capitalized costs of our oil and gas properties were in excess of the Full Cost Ceiling limitation. This impairment, which was recorded in the first quarter of 2013, was primarily due to a decline in the price of oil, additional capitalized costs and changes in production. During the year ended December 31, 2014, the Company did not recognize any oil and gas impairment expense.

Our quarterly reserve reports are prepared based on a trailing 12-month average for benchmark oil and gas prices. The weighted average oil price used to prepare reserve estimates and to calculate the Full Cost Ceiling limitation for the first quarter of 2016 is expected to decline from $50.28 to approximately $46.00 (both before further deductions for basis differentials). Assuming other variables remain substantially unchanged, we expect to record an impairment charge in the range of $3.0 million to $4.0 million during the first quarter of 2016.

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2014 and 2013 (dollars in thousands):

	2014	2013	Change Amount	Change Percent
Compensation and benefits, including directors	$4,124	$3,073	$1,051	34 %
Stock-based compensation	527	384	143	37 %
Professional fees, insurance and other	1,785	1,945	(160)	-8 %
Total	$6,436	$5,402	$1,034	19 %

General and administrative expenses increased by $1.0 million for the year ended December 31, 2014 compared to the year ended December 31, 2013. Substantially all of this increase was attributable to increases in compensation and benefits, which was driven by (i) an increase in executive retirement expense of $0.5 million related to the retirement of a former executive officer, (ii) a severance payment of $0.2 million related to the retirement of a second executive officer, and (iii) an increase in board of directors' compensation of $0.1 million.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2014 and 2013 (dollars in thousands):

			Change	
	2014	2013	Amount	Percent
Realized gain (loss) on oil price risk derivatives	$316	$(338)	$654	193 %
Unrealized gain (loss) on oil price risk derivatives	266	(737)	1,003	136 %
Gain on sale of assets	112	760	(648)	-85 %
Loss on investments	-	(2,264)	2,264	100 %
Rental and other income	88	168	(80)	-48 %
Interest expense	(385)	(429)	44	10 %
Total	$397	$(2,840)	$3,237	114 %

We recognized a realized gain on oil price risk derivatives of $0.3 million for the year ended December 31, 2014 compared to a loss of $0.3 million for 2013. We recognized an unrealized gain on oil price risk derivatives of $0.3 million for the year ended December 31, 2014 compared to a loss of $0.7 million for 2013. The 2014 realized and unrealized gains are indicative of the decline in the market for crude oil whereby our net realized price during the fourth quarter of 2014 was 27% lower than for the fourth quarter of 2013.

During the year ended December 31, 2014, we recorded a gain on the sale of assets of $0.1 million from the sale of non-oil and gas related property and equipment. During the year ended December 31, 2013, we recorded a gain on the sale of assets of $0.8 million, primarily related to the sale of our corporate aircraft and related facilities.

During the year ended December 31, 2013, we recorded an equity loss of $0.1 million from our unconsolidated investment in Standard Steam Trust LLC ("SST"). At December 31, 2013, we fully impaired the investment in SST for $2.2 million which resulted in total investment losses of $2.3 million. Since the carrying value of our investment in SST was reduced to zero, we no longer record our share of equity in earnings or losses of SST and therefore recorded no equity income or losses related to SST in 2014.

As a result of lower average debt balances, interest expense decreased slightly during the year ended December 31, 2014.

Discontinued Operations. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations for all periods presented in this report. As of December 31, 2015, we recognized an impairment charge of $22.6 million when we determined that the carrying value could not be recovered. During the years ended December 31, 2014 and 2013, the costs of operating our water treatment plant on the mine property, holding costs to maintain permits, and general corporate overhead associated with the mine property were expensed as incurred. The total operating and holding expenses amounted to $3.1 million for the year ended December 31, 2014 compared to $3.2 million for 2013.

During the year ended December 31, 2013, also had discontinued operations related to the Remington Village apartment complex that was sold in September 2013. During 2013 we recognized net rental earnings of $0.4 million for the period prior to the sale of Remington Village, and we had an impairment loss of $0.1 million for a loss from the discontinued operations of Remington Village of $0.3 million in 2013.

Non-GAAP Financial Measures- Adjusted EBITDAX

Adjusted EBITDAX represents income (loss) from continuing operations as further modified to eliminate impairments, depreciation, depletion and amortization, stock-based compensation expense, loss on investments and non-operating income or expense, income taxes, unrealized derivative gains and losses, interest expense, exploration expense, and other items set forth in the table below. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated, such as the employee severance charges incurred in 2015.

Adjusted EBITDAX is a non-GAAP measure that is presented because we believe it provides useful additional information to investors and analysts as a performance measure. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our wholly-owned subsidiary, Energy One LLC, is also subject to a debt to adjusted EBITDAX ratio as one of the financial covenants under its Credit Facility and the calculation for purposes of the Credit Facility differs from our financial reporting definition.

The following table provides reconciliations of income (loss) from continuing operations to adjusted EBITDAX for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Income (loss) from continuing operations (GAAP)	$(67,284)	$1,017	$(4,515)
Impairment of oil and gas properties	57,676	-	5,828
Depreciation, depletion and amortization	8,412	14,685	13,623
Loss on investments	68	-	2,264
Stock-based compensation	948	527	384
Employee severance costs	504	-	-
Gain on sale of assets	(121)	(112)	(760)
Interest expense	263	385	429
Adjusted EBITDAX (Non-GAAP)	$466	$16,502	$17,253

Liquidity and Capital Resources

The following table sets forth certain measures about our liquidity as of December 31, 2015 and 2014:

	2015	2014	Change
Cash and equivalents	$3,354	$4,010	$(656)
Working capital deficit [(1)]	(9,778)	(654)	(9,124)

Oil and gas standardized measure [2]	17,768	81,889	(64,121)
Total assets	33,132	123,523	(90,391)
Outstanding debt under Credit Facility	6,000	6,000	-
Borrowing base under Credit Facility	6,000	24,500	(18,500)
Total shareholders' equity	15,475	107,395	(91,920)
Select Ratios			
Current ratio [3]	0.41 to 1.00	0.92 to 1.00	
Debt to equity ratio [4]	0.39 to 1.00	0.06 to 1.00	

(1) Working capital deficit is computed by subtracting total current liabilities from total current assets.

(2) The standardized measure is widely used in the oil and gas industry and is considered by lenders, institutional investors and professional analysts when comparing companies. See Footnote 17 to the consolidated financial statements included in Item 8 of this report for further information about the standardized measure and changes therein.

(3) The current ratio is computed by dividing total current assets by total current liabilities.

(4) The debt to equity ratio is computed by dividing total debt by total shareholders’ equity.

As of December 31, 2015, we have a working capital deficit of $9.8 million compared to a working capital deficit of $0.7 million as of December 31, 2014, an increase of $9.1 million. As discussed below, this increase was primarily attributable to (i) the classification of $6.0 million of borrowings under our revolving credit facility as a current liability in 2015, and (ii) the recognition of contingent liabilities of $3.8 million associated with disputed ownership interests.

Our sole source of debt financing is a revolving Credit Facility with Wells Fargo Bank N.A. With lower oil and gas prices during 2015, Wells Fargo decreased the borrowing base by $18.5 million to $6.0 million which is the borrowing base in effect as of December 31, 2015. Outstanding borrowings as of December 31, 2015 and 2014 were $6.0 million, but we did not have any unused borrowing availability as of December 31, 2015. During 2015, we violated certain covenants in our Credit Facility and we project that we may have further violations during 2016. Accordingly, this debt is classified as a current liability as of December 31, 2015. While the lender has provided limited waivers for our past noncompliance, there is no assurance that it will continue to do so if we are non-compliant in the future. The ongoing availability of this Credit Facility through the maturity date of July 30, 2017, or our receipt of funding from alternative sources, is critical to our ability to survive until oil and gas prices recover.

During 2015 and 2014, we received significant overpayments due to an operator’s failure to timely recognize the payout implications of our joint operating agreements. During the second quarter of 2015, the operator corrected its records and has elected to begin withholding the net revenues from all of our wells that it operates to recover these overpayments. As of December 31, 2015, the balance of the overpayment was approximately $4.2 million and based on the oil and gas prices and costs used in our reserve report as of December 31, 2015, this liability is expected to be settled in full by the first quarter of 2019, but under higher pricing scenarios this liability could be repaid earlier.

We believe certain operators have failed to allocate our share of non-consent ownership interests which results in contingent liabilities to the extent we have not been billed for our proportionate share of such interests, and contingent assets to the extent that we have not received our share of the net revenues. We record net contingent liabilities for the obligations that we believe are probable which amounted to $3.2 million as of December 31, 2015. The ultimate resolution of these uncertainties about our working interests and net revenue interests can extend over a long period of time and we cannot provide any assurance that these matters will be resolved within the next year.

Our standardized measure decreased by $64.1 million during 2015 which was primarily associated with decreases in oil and gas prices. The reduction in our total assets and shareholders’ equity is primarily associated with our net loss of $92.9 million during 2015, as discussed under *Results of Operations* herein.

During the period from September 2015 through February 2016, we completed the following actions which are expected to improve our operating results in 2016 and enable our survival:

- During the third quarter of 2015, we began to implement restructuring actions to reduce corporate overhead through a reduction in the size of the Company's workforce from 14 employees at the end of 2014 to one employee by January 2016. Additionally, in December 2015 we completed a move of our corporate headquarters to Denver, Colorado for better access to financial services and to improve access to oil and gas deal flow. We expect our restructuring and other cost-cutting actions will result in an overhead reduction of approximately $4.0 million on an annualized basis.
- In February 2016, we completed the disposition of our mining segment, including the Keystone Mine, a related water treatment plant and other related properties. While an impairment charge of $22.6 million was recognized related to this disposition, a significant objective for completing the disposition was to improve future profitability. Following the disposition, we are no longer required to operate the water treatment plant and will not be responsible for mine holding costs, which are expected to result in estimated annual cash savings of $3.0 million. We believe the disposition of our mining segment is a major step in the transformation of the Company to solely focus on our existing oil and gas business.
- In April 2016, our lender provided a limited waiver for our noncompliance with the financial covenants as of December 31, 2015 and we believe the lender will not demand repayment until an alternative lender can be obtained, although there can be no guarantee that our belief will prove to be correct.

We believe approximately $7.0 million of combined overhead and mining expense reductions have poised the Company to survive the current low commodity price environment, in combination with our attractive oil price risk derivative contracts for 118,900 barrels of oil, comprising 60% of expected production for 2016. As of December 31, 2015, the fair value of our oil price risk derivatives amounted to $1.6 million.

As of December 31, 2015, we had cash and equivalents of $3.4 million, and after payment of severance and retirement liabilities of approximately $1.4 million in January 2016, we expect to maintain cash balances of approximately $2.0 million for some time. We also expect potential investors and lenders will find our new singular industry focus, combined with attractive producing properties and a low-cost overhead structure to be an attractive vehicle to partner with the Company during this industry downturn and low commodity price environment.

We project that our capital resources at December 31, 2015, together with our 2016 cash flow from operating activities will be sufficient to fund operations and up to $0.2 million for workovers and other capital expenditures. In order to develop our proved undeveloped oil and gas properties, we are projecting expenditures of $3.1 million in 2017 and $5.0 million in 2018. Additionally, our long-term strategy is to acquire additional oil and gas properties at attractive prices. Our ability to finance our capital expenditure budgets for 2017 and 2018 and our ability to acquire additional producing properties is contingent upon our ability to obtain alternative financing to our Credit Facility and this alternative financing will need to provide for borrowing capacity substantially greater than our Credit Facility.

If we have unanticipated needs for financing in 2016, alternatives that we will consider if necessary include selling or joint venturing an interest in some of our oil and gas assets, selling our real estate assets in Wyoming, selling our marketable equity securities, issuing shares of our common stock for cash or as consideration for acquisitions, and other alternatives, as we determine how to best fund our capital programs and meet our financial obligations.

Our capital expenditure plan and our ability to obtain sufficient funding to make anticipated capital expenditures and satisfy our financial obligations are subject to numerous risks and uncertainties, including the risk of continued low commodity prices or further reductions in those prices, the risk that breaches of covenants in our Credit Facility will not be waived and will result in liquidation, bankruptcy or similar proceedings, the risk that we will be unable to enter into additional financing arrangements on acceptable terms or at all, and numerous other risks, including those discussed in *Risk Factors*.

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2015 and 2014 (in thousands):

	2015	2014	Change
Net cash provided by (used in):			
Operating activities	$2,504	$23,737	$(21,233)
Investing activities	(565)	(19,542)	18,977
Financing activities	(154)	(3,055)	2,901
Discontinued operations	(2,441)	(2,985)	544

Operating Activities. Cash provided by operating activities for the year ended December 31, 2015 was $2.5 million as compared to cash provided by operating activities of $23.7 million for 2014, a decrease of $21.2 million. This decrease is primarily related to the significant cash impact caused by the reduction in our oil and gas sales, net of production costs, for the year ended December 31, 2015 as compared to 2014.

Investing Activities. Cash used in investing activities for the year ended December 31, 2015 was $0.6 million as compared to cash used in investing activities of $19.5 million for 2014, an improvement of $18.9 million. The sole use of cash in our investing activities for 2015 was $3.6 million that was primarily capital expenditures for our oil and gas drilling activities. The primary sources of investing cash flows were (i) $1.5 million of proceeds from the settlement of a dispute about title to certain oil and gas properties, (ii) $1.3 million of previously restricted funds related to our executive retirement plan that were transferred to unrestricted funds in 2015, and (iii) $0.3 million of proceeds from the sale of fixed assets.

The primary use of cash in our investing activities for 2014 was $29.8 million for the acquisition and development of oil and gas properties and $1.2 million for the purchase of other property and equipment. The primary sources of investing cash flows during 2014 was (i) $11.6 million of proceeds from the sale of oil and gas properties, and (ii) $0.1 million of proceeds from the sale of fixed assets.

Financing Activities. Cash used by financing activities for the year ended December 31, 2015 was $0.1 million as compared to cash used in financing activities of $3.1 million for 2014, an improvement of $3.0 million. The primary use of cash in our financing activities for 2015 was $0.1 million of payments for debt issuance costs. The primary use of cash in our financing activities for 2014 was $11.0 million of principal repayments under our revolver. The primary source of financing cash flows during 2014 was $8,000 of borrowings under our revolver.

Discontinued Operations. Cash used in our discontinued operations was $2.4 million for the year ended December 31, 2015 as compared to $3.0 million for 2014, an improvement of $0.6 million. The improvement in 2015 was primarily due to a refund of $0.4 million for performance bonds and a reduction in operating expenses of $0.1 million.

Contractual Obligations

The following table summarizes our contractual obligations on an undiscounted basis as of December 31, 2015, and the period when each contractual obligation is due (dollars in thousands):

	2016	2017	2018	2019	2020	Thereafter	Total
Credit facility borrowings (1)	$6,000	$-	$ -	$ -	$ -	$ -	$6,000
Interest payments (2)	180	104	-	-	-	-	284
Executive retirement plan	583	-	-	-	-	-	583
Severance agreements	374	-	-	-	-	-	374
Operating lease	88	59	-	-	-	-	147
Asset retirement obligations (3)	-	120	37	44	16	821	1,038
Total	$7,225	$283	$ 37	$ 44	$ 16	$ 821	$8,426

(1) Due to expected financial covenant violations in 2016, the lender is expected to have the ability to accelerate the maturity date of the Credit Facility from the current date of July 30, 2017.

(2) Without regard to the lender's right to demand acceleration discussed above, future interest payments under our Credit Facility are based on the assumption that the current borrowings of $6.0 million remain outstanding until the maturity date and that the interest rate in effect as of December 31, 2015 of 2.95% remains in effect through maturity.

(3) Amounts shown represent estimated future plugging and abandonment costs. The timing and amount of the ultimate settlement of these obligations is unknown and can be impacted by economic factors, a change in development plans, and federal and state regulations.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity will be consolidated in our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions during the three-year period ended December 31, 2015.

Item 7A – Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. The market prices for oil and gas have been highly volatile and are likely to continue to be highly volatile in the future, which could impact our prospective revenues. A 10% fluctuation in the price received for oil and gas production would have had an approximate $1.0 million impact on our 2015 annual revenues.

To mitigate some of our commodity risk, we use derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk. We do not hold or issue derivative instruments for trading purposes. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, such use may limit our ability to benefit from favorable price movements. We may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the existing positions.

All of our commodity derivative contracts have been entered into with our lender, Wells Fargo Bank, N.A., as described below. The derivative contracts are priced using WTI quoted prices. Commodity derivative contracts are accounted for using the mark-to-market accounting method and accordingly we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on oil price risk derivatives in our consolidated statements of operations. The net gain realized by us related to these instruments was $1.6 million for the year ended December 31, 2015. We recognized a gain of $0.6 million for the year ended December 31, 2014 and a loss of $1.1 million for the year ended December 31, 2013.

Presented below is a summary of outstanding “costless collars” with Wells Fargo as of December 31, 2015 (which total an aggregate of 118,900 barrels of oil production during 2016):

Settlement Period		Quantity	Contract Price	
Begin	End	(bbls/ day)	Put	Call
1/1/16	6/30/16	350	$57.50	$66.80
7/1/16	12/31/16	300	$50.00	$65.25

As of December 31, 2015, the aggregate fair value of oil price risk derivatives was an asset of $1.6 million. We did not have any commodity derivative contracts in place at December 31, 2014.

Interest Rate Risk. At December 31, 2015, we had long-term debt of $6.0 million at a variable rate pursuant to our Wells Fargo Credit Facility. The interest rate that we pay on amounts borrowed under the Credit Facility is derived from the Eurodollar rate and a margin that is applied to the Eurodollar rate. The margin that we pay is based upon the percentage of our available borrowing base that we utilize at the beginning of the quarter. At December 31, 2015, the borrowing base for our Credit Facility was $6.0 million and we did not have any unused borrowing availability. At this level of utilization, the Credit Facility requires us to pay a margin of 2.75%. Our interest rate under the Credit Facility as of December 31, 2015 was 2.95%. An increase in our interest rate by 10% to an effective rate of 3.25% would increase our annual interest expense by approximately $18,000.

Item 8 – Financial Statements and Supplementary Data

Financial statements meeting the requirements of Regulation S-X are included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

U.S. Energy Corp.

We have audited the accompanying consolidated balance sheets of U.S. Energy Corp. and subsidiary as of December 31, 2015 and 2014, and the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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 financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall 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 U.S. Energy Corp. and subsidiary as of December 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has a working capital deficit and an accumulated deficit and has incurred recurring losses from operations. While the lender has provided a limited waiver for non-compliance with the financial covenants in the Company's credit agreement as of December 31, 2015, the Company expects to violate the financial covenants as of March 31, 2016. Accordingly, the entire balance has been classified as a current liability as of December 31, 2015. While the lender has provided limited waivers for the Company's past noncompliance, there is no assurance that it will continue to do so in the future. These factors raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters also are described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Denver, Colorado

April 14, 2016

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2015 AND 2014

(In Thousands, Except Share and Per Share Amounts)

	2015	2014
ASSETS		
Current assets:		
Cash and equivalents	$3,354	$4,010
Oil and gas sales receivable	1,143	3,177
Oil price risk derivatives	1,634	-
Discontinued operations - assets of mining segment	318	-
Marketable equity securities	251	25
Other current assets	136	288
Total current assets	6,836	7,500
Oil and gas properties under full cost method:		
Unevaluated properties and exploratory wells in progress	5,664	12,545
Evaluated properties	97,912	147,486
Less accumulated depreciation, depletion and amortization	(80,144)	(71,762)
Net oil and gas properties	23,432	88,269
Other assets:		
Property and equipment, net	2,658	2,939
Discontinued operations - assets of mining segment	-	23,475
Other assets	206	1,340
Total other assets	2,864	27,754
Total assets	$33,132	$123,523
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities:		
Payable to Major Operator	$4,159	$5,189
Contingent ownership interests	3,108	-
Other	1,775	2,252
Accrued compensation and benefits	1,352	511
Current portion of long-term debt	6,000	-
Discontinued operations of mining properties	204	188

Other current liabilities	16	14
Total current liabilities	16,614	8,154
Noncurrent liabilities:		
Long-term debt, less current portion	-	6,000
Asset retirement obligations	1,038	945
Other liabilities	5	1,029
Total noncurrent liabilities	1,043	7,974
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, par value $0.01 per share. Authorized 100,000 shares, no shares issued	-	-
Common stock, $0.01 par value; unlimited shares authorized; 28,199,735 shares issued and outstanding	282	280
Additional paid-in capital	124,898	123,980
Accumulated deficit	(109,705)	(16,809)
Other comprehensive loss	-	(56)
Total shareholders' equity	15,475	107,395
Total liabilities and shareholders' equity	$33,132	$123,523

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

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In Thousands, Except Share and Per Share Amounts)

	2015	2014	2013
Revenue:			
Oil	$9,047	$28,331	$31,214
Natural gas and liquids	1,249	4,048	2,433
Total revenue	10,296	32,379	33,647
Operating expenses:			
Oil and gas operations:			
Production costs	7,352	10,638	10,469
Depreciation, depletion and amortization	8,412	14,685	13,623
Impairment of oil and gas properties	57,676	-	5,828
General and administrative:			
Compensation and benefits, including directors	2,602	4,124	3,073
Stock-based compensation	948	527	384
Employee severance costs	504	-	-
Professional fees, insurance and other	1,866	1,785	1,945
Total operating expenses	79,360	31,759	35,322
Operating income (loss)	(69,064)	620	(1,675)
Other income (expense):			
Realized gain (loss) on oil price risk derivatives	(75)	316	(338)
Unrealized gain (loss) on oil price risk derivatives	1,634	266	(737)
Gain on sale of assets	121	112	760
Loss on investments	(68)	-	(2,264)
Rental and other income	431	88	168
Interest expense	(263)	(385)	(429)
Total other income (expense)	1,780	397	(2,840)
Income (loss) from continuing operations	(67,284)	1,017	(4,515)
Discontinued operations:			
Discontinued operations	(2,992)	(3,108)	(2,744)

Impairment loss on discontinued operations	(22,620)	-	(120)
Loss from discontinued operations	(25,612)	(3,108)	(2,864)
Net loss	(92,896)	(2,091)	(7,379)
Change in fair value of marketable equity securities	56	(44)	(113)
Comprehensive loss	$(92,840)	$(2,135)	$(7,492)
Earnings (loss) per share- basic			
Continuing operations	$(2.40)	$0.04	$(0.16)
Discontinued operations	(0.91)	(0.12)	(0.11)
Total	$(3.31)	$(0.08)	$(0.27)
Earnings (loss) per share- diluted			
Continuing operations	$(2.40)	$0.04	$(0.16)
Discontinued operations	(0.91)	(0.11)	(0.11)
Total	$(3.31)	$(0.07)	$(0.27)
Weighted average shares outstanding			
Basic	28,065,000	27,833,000	27,679,000
Diluted	28,065,000	28,099,000	27,679,000

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

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In Thousands, Except Share Amounts)

	Common Stock Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total
Balances, December 31, 2012	27,652,602	$ 277	$ 123,078	$ (7,339)	$ 101	$ 116,117
Stock-based compensation	-	-	184	-	-	184
Issuance of common stock for services	30,000	-	48	-	-	48
Issuance of common stock to fund ESOP contribution	53,276	-	200	-	-	200
Unrealized loss on marketable equity securities	-	-	-	-	(113)	(113)
Net loss	-	-	-	(7,379)	-	(7,379)
Balances, December 31, 2013	27,735,878	277	123,510	(14,718)	(12)	109,057
Stock-based compensation	-	-	318	-	-	318
Exercise of employee stock options	157,950	2	(64)	-	-	(62)
Exercise of stock purchase warrants	12,112	-	8	-	-	8
Issuance of common stock to fund ESOP contribution	141,721	1	208	-	-	209
Unrealized loss on marketable equity securities	-	-	-	-	(44)	(44)
Net loss	-	-	-	(2,091)	-	(2,091)
Balances, December 31, 2014	28,047,661	280	123,980	(16,809)	(56)	107,395
Issuance of common stock upon vesting of restricted common stock, net	152,074	2	330	-	-	332
Stock-based compensation	-	-	588	-	-	588
Realized loss on marketable equity securities	-	-	-	-	56	56
Net loss	-	-	-	(92,896)	-	(92,896)
Balances, December 31, 2015	28,199,735	$ 282	$ 124,898	$ (109,705)	$ -	$ 15,475

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

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In Thousands)

	2015	2014	2013
Cash flows from operating activities:			
Net loss	$(92,896)	$(2,091)	$(7,379)
Loss from discontinued operations	25,612	3,108	2,864
Income (loss) from continuing operations	(67,284)	1,017	(4,515)
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	8,557	14,833	13,772
Impairment of oil and gas properties	57,676	-	5,828
Change in fair value of oil price risk derivative	(1,634)	(266)	737
Losses related to equity method investment	-	-	2,264
Gain on sale of assets	(121)	(112)	(760)
Stock-based compensation and services	948	527	384
Other	(110)	585	132
Changes in operating assets and liabilities:			
Decrease (increase) in:			
Oil and gas sales receivable	2,034	2,571	(1,619)
Other assets	63	165	8
Increase (decrease) in:			
Accounts payable	1,126	909	3,617
Oil and gas operator overpayments	1,429	3,983	-
Accrued compensation and benefits	(188)	(436)	172
Other liabilities	8	(39)	123
Net cash provided by operating activities	2,504	23,737	20,143
Cash flows from investing activities:			
Capital expenditures	(3,620)	(31,044)	(20,799)
Proceeds from sale of oil and gas properties and other	264	11,624	2,628
Proceeds from settlement of property litigation	1,500	-	-
Net change in restricted investments	1,291	(122)	(48)
Net cash used in investing activities:	(565)	(19,542)	(18,219)
Cash flows from financing activities:			
Redemption of common stock	(29)	(55)	-

Proceeds from debt financings	-	8,000	2,000
Principal payments under debt financings	-	(11,000)	(12,821)
Payments for debt issuance costs	(125)	-	-
Net cash used in financing activities	(154)	(3,055)	(10,821)
Discontinued operations:			
Net cash used in operating activities	(2,440)	(2,985)	(2,728)
Net cash provided by (used in) investing activities	(1)	-	14,655
Net cash provided by (used in) discontinued operations	(2,441)	(2,985)	11,927
Net increase (decrease) in cash and equivalents	(656)	(1,845)	3,030
Cash and equivalents, beginning of year	4,010	5,855	2,825
Cash and equivalents, end of year	$3,354	$4,010	$5,855

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

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS, Continued

FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

(In Thousands)

	2015	2014	2013
Supplemental disclosures of cash flow information:			
Cash payments for income taxes	$-	$-	$-
Cash payments for interest	$210	$385	$274
Non-cash investing and financing activities:			
Unrealized loss on marketable equity securities	$11	$44	$113
Increase (decrease) in accrued capital expenditures for oil and gas properties	$112	$(2,565)	$142
Net additions to oil and gas properties through asset retirement obligations	$61	$281	$131

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

U.S. ENERGY CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in Thousands, Except Per Share Amounts)

1. ORGANIZATION, OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations

U.S. Energy Corp. (collectively with its subsidiaries referred to as the "Company") was incorporated in the State of Wyoming on January 26, 1966. The Company's principal business activities are focused in the acquisition, exploration and development of oil and gas properties in the United States.

Basis of Presentation

As discussed in Note 6, during the fourth quarter of 2015 the Company began accounting for its mining operations as a Discontinued Operation. Accordingly, certain reclassifications have been made to the prior period balances in order to conform to the current period presentation. These and other reclassifications had no impact on working capital, net loss, shareholders' equity or cash flows as previously reported.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves that are used in the calculation of depreciation, depletion, amortization and impairment of the carrying value of evaluated oil and gas properties; production and commodity price estimates used to record accrued oil and gas sales receivable; valuation of commodity derivative instruments; the impact of commodity prices and other events affecting impairment of mining properties; and the cost of future asset retirement obligations. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Principles of Consolidation

The accompanying financial statements include the accounts of the Company and its wholly owned subsidiaries Energy One, LLC ("Energy One"), Highlands Ranch LLC ("Highlands Ranch") and Remington Village, LLC ("Remington Village"). All inter-company balances and transactions have been eliminated in consolidation. Certain prior period amounts have been reclassified to conform to the current period presentation of the accompanying financial statements.

Cash and Equivalents

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

Oil and Gas Sales Receivable

The Company's accounts receivable consist primarily of receivables from joint interest operators for the Company's share of oil, gas, and natural gas liquids ("NGLs"). Generally, the Company's oil and gas sales receivable are collected within three months and the Company has had minimal bad debts. Collectability is dependent upon the financial wherewithal of the joint interest operators and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2015 and 2014, the Company had not provided for an allowance for doubtful accounts.

Marketable Equity Securities

The Company categorizes its marketable equity securities as available-for-sale. Accordingly, increases or decreases in the fair value are generally presumed to be temporary and are recorded as a component of shareholders' equity within comprehensive income or loss. The Company periodically evaluates if cumulative losses are indicative of other than temporary impairment whereby a loss is recognized when management determines that the value is unlikely to recover to the Company's cost basis. Gains or losses from sales are recorded in operations when realized.

U.S. ENERGY CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

(Dollars in Thousands, Except Per Share Amounts)

Oil and Gas Properties

The Company follows the full cost method of accounting for its oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center are subject to depreciation, depletion and amortization ("DD&A") using the equivalent unit-of-production method, based on total proved oil and gas reserves. For financial statement presentation, DD&A includes accretion expense related to asset retirement obligations. Excluded from amounts subject to DD&A are costs associated with unevaluated properties, including exploratory wells in progress.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability, or the cost center ceiling (the "Ceiling Test"). The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period; and costs, adjusted for contract provisions and financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (ii) the cost of unevaluated properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, reduced by (iv) the income tax effects related to differences between the book and tax basis of the crude oil and gas properties. If the net book value reduced by the related net deferred income tax liability (if any) and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs. Since all of the Company's oil and gas properties are located within the United States, the Company only has one cost center for which a quarterly Ceiling Test is performed.

Property and Equipment

Land, buildings, improvements, machinery and equipment are carried at cost. Depreciation of buildings, improvements, machinery and equipment is provided principally by the straight-line method over estimated useful lives as follows:

	Years
Real estate:	
Buildings	20 to 45
Building improvements	10 to 25
Land improvements	10 to 35
Administrative assets:	
Computers and software	3 to 10
Office furniture and equipment	5 to 20
Vehicles and other	5

Discontinued Operations- Mining Properties

Effective January 1, 2015, the Company adopted new accounting guidance related to the recognition and presentation of discontinued operations in its financial statements. Under the revised guidance, beginning in 2015 only disposals of businesses that represent strategic shifts that have a major effect on an organization’s operations and financial results will be reported in discontinued operations. Accordingly, as discussed in Note 6, the Company’s disposal of its mining segment qualified for reporting as discontinued operations in the accompanying financial statements. The presentation of the Company’s 2013 discontinued operations was not changed by this new accounting guidance.

The Company capitalized all costs incidental to the acquisition of mining properties. Mining equipment was depreciated using the straight line method over estimated useful lives that ranged from 10 to 20 years. Costs of operating a related water treatment plant on the mine property, holding costs to maintain permits, mining exploration costs and general corporate overhead were expensed as incurred. Capitalized costs were charged to operations to the extent it was subsequently determined that the mine property is not economic due to permanent decreases in market prices of commodities, excessive production costs, depletion of the mineral resource, or other factors.

U.S. ENERGY CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

(Dollars in Thousands, Except Per Share Amounts)

Long-Lived Assets

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amount may not be recoverable. If estimated future cash flows, on an undiscounted basis, are less than the carrying amount of the related asset, an asset impairment charge is recognized, and measured as the amount by which the carrying value exceeds the estimated fair value. Changes in significant assumptions underlying future cash flow estimates may have a material effect on the Company’s financial position and results of operations.

Long-lived assets are classified as held for sale when the Company commits to a plan to sell the assets. Such assets are classified within current assets if there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

Derivative Instruments

The Company uses derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of the Company’s exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, the Company recognizes all unrealized and realized gains and losses that are related to these contracts currently in earnings and classifies them as gain (loss) on derivative instruments, net in the Company’s consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

Asset Retirement Obligations

The Company records the estimated fair value of restoration and reclamation liabilities related to its oil and gas properties and its inactive mining properties as of the date that the liability is incurred. The Company reviews the liability each quarter and determines if a change in estimate is required, and accretion of the discounted liability is recorded based on the passage of time. Final determinations are made during the fourth quarter of each year. The Company deducts any actual funds expended for restoration and reclamation during the quarter in which it occurs.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, natural gas, and NGLs. In the accompanying statements of operations, revenue from gas includes sales of both natural gas and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in lease operating expense in the accompanying statements of operations. The Company records oil and gas revenue under the sales method of accounting. Gas balancing obligations as of December 31, 2015 and 2014 were not significant. Revenue is recorded in the month that the production is delivered to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, market prices, and other factors as the basis for these estimates.

Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

Stock-Based Compensation

The Company measures the cost of employee and director services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date. The Company computes the fair values of its options granted to employees using the Black Scholes pricing model. The Company recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. For awards granted which contain a graded vesting schedule, and the only condition for vesting is a service condition, compensation cost is recognized as an expense on a straight-line basis over the requisite service period as if the award was, in substance, a single award. Stock-based compensation expense is recognized based on awards ultimately expected to vest whereby estimates of forfeitures are based upon historical experience.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

(Dollars in Thousands, Except Per Share Amounts)

Income Taxes

The Company recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

Additionally, the Company recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. At December 31, 2015 and 2014, management believed it was more likely than not that such tax benefits would not be realized and a valuation allowance has been provided. The Company would recognize any interest and penalties related to uncertain tax positions as a component of income tax expense.

Earnings Per Share

Basic net income (loss) per share is computed based on the weighted average number of common shares outstanding. Diluted net income (loss) per share is calculated by dividing net income or loss by the diluted weighted average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options. When there is a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are excluded from the calculation of net income (loss) per share. The treasury stock method is used to measure the dilutive impact of in-the-money stock options.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of shareholders’ equity instead of net income (loss).

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, *"Revenue from Contracts with Customers"*. This comprehensive guidance will replace all existing revenue recognition guidance and is effective for annual reporting periods beginning after December 15, 2017, and interim periods therein. The Company is currently assessing the impact this standard will have on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, *"Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern"* that will require management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Management will be required to provide certain footnote disclosures if it concludes that substantial doubt exists or when its plans alleviate substantial doubt about the Company's ability to continue as a going concern. This ASU becomes effective for annual periods beginning in 2016 and for interim reporting periods starting in the first quarter of 2017. The Company is currently evaluating the impact of this standard on its financial statements.

In November 2014, the FASB issued ASU 2014-16, *"Derivatives and Hedging: Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity*". This ASU does not change the current criteria in GAAP for determining when separation of certain embedded derivative features in a hybrid financial instrument is required, but clarifies how current GAAP should be interpreted in the evaluation of the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share, reducing existing diversity in practice. This ASU will be effective for interim periods beginning on January 1, 2016. The Company is evaluating this ASU to determine if adoption will have a material impact on the Company's consolidated financial statements.

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In January 2015, the FASB issued ASU 2015-01, "*Income Statement—Extraordinary and Unusual Items"*, that will simplify income statement classification by removing the concept of extraordinary items from GAAP. Upon adoption, the separate disclosure of extraordinary items after income from continuing operations in the income statement will no longer be permitted. The Company adopted this standard as of January 1, 2016.

In February 2015, the FASB issued ASU No. 2015-02, *"Consolidation: Amendments to the Consolidation Analysis"*. The new standard is intended to improve targeted areas of consolidation guidance for legal entities such as limited partnerships, limited liability corporations, and securitization structures. The new guidance must be adopted for interim and annual financial statements issued for the year ending December 31, 2016. The adoption of this standard is not expected to have a material impact on the Company's consolidated financial statements.

During 2015, the FASB issued ASUs No. 2015-03 and No. 2015-15 titled *"Interest-Imputation of Interest",* which generally requires the presentation of debt issuance costs as a direct deduction from the carrying amount of the related debt liabilities. However, for debt issuance costs related to line-of-credit arrangements, the Company will be permitted to continue presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The Company expects to continue to present its deferred line of credit fees as an asset in its consolidated balance sheets.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities.* This ASU is intended to improve the recognition and measurement of financial instruments. Among other things, this ASU requires certain equity investments to be measured at fair value with changes in fair value recognized in net income. This guidance is effective for fiscal years beginning after December 15, 2017, and interim periods therein. The Company is currently assessing the impact this guidance will have on its consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases*, which will supersede the existing guidance for lease accounting. This ASU will require lessees to recognize leases on their balance sheets, and leaves lessor accounting largely unchanged. This guidance is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, and early adoption is permitted. The Company is currently assessing the impact this guidance will have on its consolidated financial statements.

2. LIQUIDITY

As of December 31, 2015, the Company has a working capital deficit of $9,778 and an accumulated deficit of $109,705. Additionally, the Company incurred a net loss of $92,896 for the year ended December 31, 2015. During 2015, the Company was in violation of certain covenants in its credit agreement and the Company expects future violations in 2016, which requires the entire balance to be classified as a current liability. While the lender has provided limited waivers for the Company's past noncompliance, there is no assurance that it will continue to do so in the future.

During the period from September 2015 through February 2016, the Company completed the following actions which are expected to improve the Company's operating results in 2016 and enable the Company to survive the current oil and gas industry price environment:

- During the third quarter of 2015, the Company began to implement restructuring actions to reduce corporate overhead through a reduction in the size of the Company's workforce from 14 employees at the end of 2014 to one employee by January 2016. Additionally, in December 2015 the Company completed a move of its corporate headquarters to Denver, Colorado for better access to financial services and to improve access to oil and gas deal flow. Management expects its restructuring and other cost-cutting actions will result in an overhead reduction of approximately $4,000 on an annualized basis.
- As discussed in Note 6, in February 2016 the Company completed the disposition of its mining segment, including the Keystone Mine, a related water treatment plant and other related properties. While an impairment charge of $22,620 was recognized related to this disposition, a significant objective for completing the disposition was to improve future profitability. Following the disposition, the Company is no longer required to operate the water treatment plant and will not be responsible for mine holding costs, which are expected to result in estimated annual cash savings of $3,000. Management believes the disposition of the Company's mining segment is a major step in the transformation of U.S. Energy Corp. to solely focus on its existing oil and gas business.

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(Dollars in Thousands, Except Per Share Amounts)

- As discussed in Note 19, in April 2016 the Company's lender provided a limited waiver for the Company's noncompliance with the credit agreement covenants as of December 31, 2015, and management believes the lender will not demand repayment until an alternative lender can be obtained.

Management believes approximately $7,000 of combined overhead and mining expense reductions have poised the Company to survive the current low commodity price environment, in combination with our attractive oil price risk derivative contracts for 118,900 barrels of oil which is 60% of expected production for 2016.

As of December 31, 2015, the Company had cash and equivalents of $3,354, and after payment of severance and retirement liabilities in January 2016, the Company expects to maintain cash balances of approximately $2,000 for some time. Management also expects potential investors and lenders will find the Company's new singular industry focus, combined with attractive producing properties and a low-cost overhead structure to be an attractive vehicle to partner with the Company during this industry downturn and low commodity price environment.

3. OIL PRICE RISK DERIVATIVES

The Company's wholly-owned subsidiary Energy One has entered into crude oil derivative contracts ("economic hedges") with Wells Fargo, the Company's lender as discussed further in Note 7. The derivative contracts are priced based on West Texas Intermediate ("WTI") quoted prices for crude oil. The Company is a guarantor of Energy One's obligations under the economic hedges. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of the Company's future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage the Company's exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit the Company's ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions. The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features. Presented below is a summary of outstanding "costless collars" with Wells Fargo as of December 31, 2015 (which total an aggregate of 118,900 barrels of oil production during 2016):

	Quantity	Contract Price

Settlement Period Begin	End	(bbls/ day)	Put	Call
1/1/16	6/30/16	350	$57.50	$66.80
7/1/16	12/31/16	300	$50.00	$65.25

As of December 31, 2015, the aggregate fair value of oil derivative put contracts was an asset of $1,674 and the aggregate fair value of oil derivative call contracts was a liability of $40. Since these contracts are with the same counterparty, the Company recognizes the net asset of $1,634 in the accompanying balance sheet as of December 31, 2015. Since all of the derivative contracts expire within one year of the balance sheet date, the entire amount is included in current assets. There were no derivative contracts in place at December 31, 2014.

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are included in unrealized gain (loss) on oil price risk derivatives in the consolidated statements of operations.

4. OIL AND GAS PRODUCING ACTIVITIES

Acquisitions

In May 2014, the Company entered into a Participation Agreement to acquire a 33% interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The Company's share of the acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage had an initial two well commitment and a 12.5% carried working interest for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. The Seller also retained a 25% back-in working interest after 115% of project payout has been received by the Company. The Company paid approximately $3,900 to enter into the transaction, which included leasehold and farm-in acquisition costs as well as a proportionate share of drilling costs for the initial test well in the prospect. As of December 31, 2015, approximately $252 is included in unevaluated properties and the remainder of the costs are included in evaluated properties.

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(Dollars in Thousands, Except Per Share Amounts)

Divestitures

In May 2014, the Company entered into an agreement to sell some of its Williston Basin assets. Under the terms of the agreement, the Company sold its interest in approximately 286 net acres and 16 gross (0.62 net) producing wells in Williams and McKenzie Counties, North Dakota. The transaction closed in June 2014 with an effective date of January 1, 2014. The Company received approximately $12,200 at closing which included $681 in adjustments related to revenue receivable and accounts payable through the date of closing. The balance of the sale proceeds of approximately $11,500 was recorded as a reduction of evaluated properties in the full cost pool.

As discussed in Note 10, in April 2015 the Company settled a quiet title action that was initiated in October 2013, whereby the Company received $1,500 in exchange for releasing its interest in the subject lease. Accordingly, the proceeds from the settlement were accounted for as a reduction of the Company's evaluated oil and gas properties in 2015.

Ceiling Test and Impairment

The reserves used in the Ceiling Test incorporate assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In the calculation of the Ceiling Test for the year ended December 31, 2015, the Company used $50.28 per barrel for oil and $2.59 per MMbtu for natural gas (as further adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of the Company's producing properties. The discount factor used was 10%.

The Company recorded no proved property impairments related to its oil and gas properties during the year ended December 31, 2014. For the years ended December 31, 2015 and 2013, impairment of the Company's oil and gas properties amounted to $57,676 and $5,828, respectively. These impairment charges were primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. Recent declines in the price of oil have significantly increased the risk of Ceiling Test write-downs in future periods.

Capitalized Costs

The following table presents the Company's capitalized costs associated with oil and gas producing activities as of December 31, 2015 and 2014:

	2015	2014
Oil and Gas Properties:		
Unevaluated properties:		
Unproved leasehold costs	$5,664	$10,188
Exploratory wells in progress	-	2,357
Evaluated properties in full cost pool	97,912	147,486
Less accumulated depreciation, depletion and amortization	(80,144)	(71,762)
Net capitalized costs	$23,432	$88,269

The Company's depreciation, depletion and amortization per equivalent BOE was $26.80 for 2015, $31.56 for 2014, and $32.06 for 2013.

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties consist of leasehold costs and exploratory wells in progress which are excluded from the DD&A calculation and the Ceiling Test until a determination about the existence of proved reserves can be completed. As of December 31, 2015, unevaluated oil and gas properties consisted solely of unproved lease acquisition costs of $5,664. As of December 31, 2014, unevaluated oil and gas properties consisted of unproved lease acquisition costs of $10,188 and exploratory wells in progress of $2,357. The table below presents the years in which unevaluated leasehold costs were incurred:

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	As of December 31,	
Year Incurred	2015	2014
2010	$-	$103
2011	2,686	4,015
2012	267	271
2013	1,525	2,067
2014	1,153	3,732
2015	33	-
	$5,664	$10,188

During the fourth quarter of 2015, the Company transferred approximately $2,500 of unproved properties that were considered to be impaired into the full cost pool. On a quarterly basis, management reviews market conditions and other changes in circumstances related to the Company's unevaluated properties and transfers the costs to evaluated properties within the full cost pool as warranted.

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, all of which have been capitalized, are summarized as follows for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Acquisition costs:			
Proved properties	$1,658	$552	$445
Unproved properties	632	4,167	1,760
Development costs	61	8,037	9,403

Exploration costs	369	14,791	9,138
Total [1]	$2,720	$27,547	$20,746

[1] Includes amounts related to estimated asset retirement obligations of $61, $281 and $131 for the years ended December 31, 2015, 2014 and 2013, respectively.

Results of Operations

Presented below are the results of operations from oil and gas producing activities for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Oil and gas sales	$10,296	$32,379	$33,647
Production costs	(7,352)	(10,638)	(10,469)
Depreciation, depletion and amortization	(8,412)	(14,685)	(13,623)
Impairment of oil and gas properties	(57,676)	-	(5,828)
Results of operations from oil and gas producing activities	$(63,144)	$7,056	$3,727

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

(Dollars in Thousands, Except Per Share Amounts)

5. PROPERTY AND EQUIPMENT, NET

Property and equipment consists of the following as of December 31, 2015 and 2014:

	2015	2014
Real estate:		
Land	$1,033	$1,109
Buildings	4,012	4,012