10-K 1 v403699_10k.htm 10-K

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

**FORM 10-K**

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

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

For the fiscal year-ended December 31, 2014
Commission file number 000-30234

**ENERJEX RESOURCES, INC.**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Nevada** | **88-0422242** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **4040 Broadway**<br>**Suite 508**<br>**San Antonio, Texas** | **78209** |
| (Address of principal executive offices) | (Zip Code) |

**(210) 451-5545**
(Registrant's telephone number, including area code)

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

Name of each exchange on which registered:

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

Common Stock, $0.001 par value
10% Series A Cumulative Redeemable Perpetual Preferred Stock, $0.001 par value

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

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

Indicate by checkmark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
x Yes ¨ 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).
x Yes ¨ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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 ¨ (Do not check if a smaller reporting company) | Smaller reporting company x |

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

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 asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: approximately $22 million based on a share value of $7.00.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 8,406,661 shares of common stock, $0.001 par value, outstanding on March 31, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes (e.g., annual report to security holders for fiscal year ended December 24, 1980).

NONE.

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## FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that involve risks and uncertainties. The statements contained in this document that are not purely historical are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Forward-looking statements are statements regarding future events, our future financial performance, and include statements regarding projected operating results. These forward-looking statements are based on current expectations, beliefs, intentions, strategies, forecasts and assumptions and involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by these forward-looking statements. We have attempted to identify forward-looking statements by terminology including "anticipates," "believes," "can," "continue," "could," "estimates," "expects," "intends," "may," "plans," "potential," "predicts" or "should" or the negative of these terms or other comparable terminology. Although we do not make forward-looking statements unless we believe we have a reasonable basis for doing so, we cannot guarantee their accuracy. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time and it is not possible for us to predict all risk factors, nor can we address the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause our actual results to differ materially from those contained in any forward-looking statements. All forward-looking statements included in this document are based on information available to us on the date of this Annual Report on Form 10-K, and we assume no obligation to update any such forward-looking statements, except as may otherwise be required by law.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including those set forth in the "Risk Factors" section in Part I, Item 1A of this Annual Report on Form 10-K and elsewhere in this document. The factors impacting these risks and uncertainties include, but are not limited to:

- inability to attract and obtain additional development capital;
- inability to achieve sufficient future sales levels or other operating results;
- inability to efficiently manage our operations;
- effect of our hedging strategies on our results of operations;
- potential default under our secured obligations or material debt agreements;
- estimated quantities and quality of oil and gas reserves;
- declining local, national and worldwide economic conditions;
- fluctuations in the price of oil and natural gas;
- continued weather conditions that impact our abilities to efficiently manage our drilling and development activities;
- the inability of management to effectively implement our strategies and business plans;
- approval of certain parts of our operations by state regulators;
- inability to hire or retain sufficient qualified operating field personnel;
- increases in interest rates or our cost of borrowing;
- deterioration in general or regional (Colorado, Western Nebraska, Eastern Kansas and South Texas) economic conditions;
- adverse state or federal legislation or regulation that increases the costs of compliance, or adverse findings by a regulator with respect to existing operations;
- the occurrence of natural disasters, unforeseen weather conditions, or other events or circumstances that could impact our operations or could impact the operations of companies or contractors we depend upon in our operations;
- inability to acquire mineral leases at a favorable economic value that will allow us to expand our development efforts; and
- changes in U.S. GAAP or in the legal, regulatory and legislative environments in the markets in which we operate.

All references in this report to "we," "us," "our," "company" and "EnerJex" refer to EnerJex Resources, Inc. and our wholly-owned operating subsidiaries, EnerJex Kansas, Inc., Black Sable Energy, LLC, Working Interest, LLC, and Black Raven Energy, Inc., unless the context requires otherwise. We report our financial information on the basis of a December 31st fiscal year end. We have provided definitions for the oil and gas industry terms used in this report in the "Glossary" beginning on page 15 of this report.

## AVAILABLE INFORMATION

We file annual, quarterly and other reports and other information with the SEC. You can read these SEC filings and reports over the Internet at the SEC's website at www.sec.gov or on our website at www.enerjex.com. You can also obtain copies of the documents at prescribed rates by writing to the Public Reference Section of the SEC at 100 F Street, NE, Washington, DC 20549 on official business days between the hours of 10:00 am and 3:00 pm. Please call the SEC at (800) SEC-0330 for further information on the operations of the public reference facilities. We will provide a copy of our annual report to security holders, including audited financial statements, at no charge upon receipt to of a written request to us at EnerJex Resources, Inc., 4040 Broadway, Suite 508, San Antonio, Texas 78209.

## INDUSTRY AND MARKET DATA

The market data and certain other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources. In addition, some data are based on our good faith estimates.

## PART I

### ITEMS 1 AND 2. BUSINESS AND PROPERTIES.

**Company History**

We were formerly known as Millennium Plastics Corporation and were incorporated in the State of Nevada on March 31, 1999. We abandoned a prior business plan focusing on the development of biodegradable plastic materials. In August 2006, we acquired Midwest Energy, Inc., a Nevada corporation pursuant to a reverse merger. After the merger, Midwest Energy became a wholly-owned subsidiary, and as a result of the merger the former Midwest Energy stockholders controlled approximately 98% of our outstanding shares of common stock. We changed our name to EnerJex Resources, Inc. in connection with the merger, and in November 2007 we changed the name of Midwest Energy (now our wholly-owned subsidiary) to EnerJex Kansas, Inc. All of our current operations are conducted through EnerJex Kansas, Inc., Black Sable Energy, LLC, and Black Raven Energy, Inc., and our leasehold interests are held in our wholly-owned subsidiaries Black Sable Energy, LLC, Working Interest, LLC, EnerJex Kansas, Inc., and Black Raven Energy, Inc.

**Significant Developments in 2014**

The following briefly describes our most significant corporate developments occurring in 2014:

- In our Adena Field Project, we reactivated and initiated production from 7 new J-Sand oil wells and 1 new J-Sand natural gas well, recompleted and initiated water injection into 9 new secondary recovery J-Sand wells, and recompleted 2 D-sand oil wells in a secondary recovery waterflood pilot that was initiated during 2013. Preliminary production tests in this D-Sand waterflood pilot indicate that secondary recovery operations have increased reservoir pressure, fluid volumes and oil cut. Initial oil production from this pilot commenced in September 2014.

  During June and July 2014, we conducted detailed production tests on our J-Sand oil wells in order to measure oil and water volumes. Data collected from these testing operations is being utilized to optimize field operations and future development planning. The testing process resulted in inefficient run times that negatively impacted production volumes during these months. After reviewing the results of the testing information and experiencing water injection and other infrastructure constraints, EnerJex decided to upgrade its infrastructure in order to increase production capacity and decrease operating expenses. The company recently replaced key portions of the primary production infrastructure and reconfigured the water injection system to handle additional production volumes.

- In our Mississippian Project, we initiated a development drilling program in July and drilled 12 successful oil wells and three secondary recovery water injection well.

- In our Niobrara Project, we successfully completed workover operations on eleven natural gas wells. In addition we tested two wells located approximately one mile apart in a portion of our Niobrara Project located in Sedgwick County, Colorado. Each well achieved an initial production rate of more than 600 thousand cubic feet of natural gas (Mcf) per day from the Niobrara formation at a depth of approximately 2,900 feet.

  The Company has filed 17 drilling permits in in this area, where we have identified dozens of high-ranked drilling locations based on 3D seismic analysis. We have completed our assessment of the costs and timing associated with this development, including drilling and completion operations, pipeline construction, and the upgrade of an existing tap which the Company previously acquired that connects to the Trailblazer pipeline. We are currently waiting on a third party to complete the upgrade of the tap which we paid for during September. We expect to have the tap upgrade completed and all permits finalized for the 17 well drilling program by the second quarter of 2015.

- Effective after the close of trading in EnerJex common stock on May 30, 2014, the Company affected a 1-for-15 reverse stock split, by which each share of EnerJex common stock was reclassified, and changed into 1/15th of a fully paid and non-assessable share of common stock. In lieu of fractions of a share, the Company paid to holders of fractions of a share cash equal to $11.25 per share, which was the minimum value designated in the amended and restated certificate of designations affecting the reverse stock split.

- On June 16, 2014, we adopted the Amended and Restated Certificate of Designation modifying the terms of our then-existing Series A preferred stock. Concurrently with filing of that Amended and Restated Certificate of Designation, the holders of our existing Series A preferred stock exchanged each outstanding share of such existing Series A preferred stock for (i) a number of shares of our common stock into which such Series A preferred stock was then convertible immediately prior to the exchange (318,630 shares in the aggregate), and (ii) a number of shares of Series A preferred stock equal to the quotient determined by dividing (x) that portion of the holder's original Series A preferred stock purchase price that had not yet been paid in dividends, by (y) $23.75.

- On June 17, 2014 our common stock and non-dilutive Series A Cumulative Redeemable Perpetual Preferred Stock began trading on the NYSE MKT under the symbols ENRJ and ENRJ.P. The Company's common stock prior to June 17, 2014 traded on the OTCQB.

- On June 20, 2014, we closed an underwritten public offering of 639,157 shares of 10% Series A Cumulative Redeemable Perpetual Preferred Stock (liquidation preference of $25.00 per share) at a price to the public of $23.75 per share for gross proceeds of $15.2 million. The shares sold to the underwriters included 83,368 shares pursuant to a 45-day option that was exercised by the underwriters in full on June 20, 2014. The Series A Preferred Shares contain the following provisions: (i) Series A Preferred Shareholders shall receive cumulative dividends at the stated rate of 10% per annum of the $25.00 per share liquidation preference; (ii) the Series A Preferred Shares shall not be redeemable by the Company except on or after June 16, 2017 or after a Change of Control of the Company; (iii) the Series A Preferred Shares shall not have any relative, participating, option or other voting rights or powers: and (iv) the Series A Preferred Shares shall not be convertible into our common stock.

- On September 30, 2014, we acquired an 85% operated working interest in 640 acres in Weld County, Colorado, referred to herein as our Seven Cross acreage. This acreage is held by production from three existing wells including two wells that produce oil from the Niobrara and Codell formations and one well that produces oil from the J-Sand formation. This acreage is prospective for horizontal drilling targeting oil and natural gas production from the Niobrara and Codell formations. We also acquired a 100% operated working interest in 3,400 acres in Weld County, referred to herein as our Hereford acreage. This acreage is also prospective for horizontal drilling targeting oil and natural gas production from the Niobrara and Codell formations.

**Our Business**

Our principal strategy is to acquire, develop, explore and produce domestic onshore oil and natural gas properties. Our business activities are currently focused in Kansas, Colorado, Nebraska, and Texas.

Our total net proved oil and gas reserves as of December 31, 2014 were 4.4 million barrels of oil equivalents (BOE), of which 69% was oil. Of the 4.4 million BOE of total proved reserves, approximately 50% are classified as proved developed producing, approximately 19% are classified as proved developed non-producing, and approximately 31% are classified as proved undeveloped.

The total PV10 (present value) of our proved reserves as of December 31, 2014 was approximately $64 million. "PV10" means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 35, for a reconciliation to the comparable GAAP financial measure.

Except where noted, the discussion regarding our business in this Annual Report on Form 10-K is as of December 31, 2014.

**Our Colorado Properties**

The table below summarizes our current Colorado and Nebraska acreage by project name as of December 31, 2014.

| Project Name | Developed Acreage (1) | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| | Gross | Net (2) | Gross | Net (2) | Gross | Net (2) |
| Adena | 18,760 | 18,760 | - | - | 18,760 | 18,760 |
| Hereford | | | 3,400 | 3,400 | 3,400 | 3,400 |
| Seven Cross | 640 | 544 | | | 640 | 544 |
| Niobrara - Colorado (3) | 20,959 | 20,959 | 22,789 | 22,789 | 43,748 | 43,748 |
| Niobrara - Nebraska | - | - | 9,440 | 9,440 | 9,440 | 9,440 |
| Total | 40,359 | 40,263 | 35,629 | 35,629 | 75,988 | 75,892 |

(1) Developed acreage includes all acreage that was held by production as of December 31, 2014.

(2) Net acreage is based on our net working interest as of December 31, 2014.

(3) Developed acreage includes 8,360 net acres with rights limited to depths below the Niobrara formation.

### *Adena Field Project*

The Adena Field Project is located in the Denver-Julesburg ("D-J") Basin in Morgan County, Colorado, where we owned a 100% working interest in 18,760 gross acres as of December 31, 2014. Our acreage position covers the majority of Adena Field, which is the third largest oil field ever discovered in Colorado behind Rangely Field and Wattenberg Field. Adena Field has cumulatively produced 75 million barrels of oil and 125 billion cubic feet of natural gas since its discovery in the early 1950s. Our acreage in this project is currently held-by-production (see "Glossary" on page 15 for definition of held-by-production). The majority of the producing wells in Adena Field were temporarily abandoned or shut-in during the mid-1980's when oil prices collapsed, and a relatively small number of wells have been produced since that time.

Approximately 106 wells on our acreage are currently shut-in or temporarily abandoned. Our current understanding of the field indicates that most of the remaining 85 shut-in oil wells are candidates for reactivation, recompletion or use in a larger scale EOR project. The same is true for the remaining 21 shut-in injection wells. We have two significant EOR project studies under way at the present time and have begun field sampling and EOR flood modeling for each project. We intend to reactivate vintage secondary recovery injection wells simultaneously with the reactivation and/or recompletion of producer wells. Recompletions and reactivations are expected to cost approximately $200,000 to $250,000 per well and are expected to result in stabilized production rates of approximately 10 barrels of oil per day. We have also identified a number of wells on our acreage that are prospective for natural gas production from the J-Sand and D-Sand formations.

As of December 31, 2014, the Adena Field Project was producing approximately 150 gross barrels of oil per day from 20 J-Sand wells and 10 D-Sand wells at a depth of approximately 5,500 feet. One J sand gas producer was temporarily shut-in because of mechanical issues with a third party compression facility. Multiple wells were also in various stages of reactivation and recompletion as of December 31, 2014 and has since recommenced production at a rate of approximately 700 mcf of natural gas per day. We intend to pursue our reactivation and recompletion strategy in 2015 once oil prices recover.

Our working interest in our Adena Field Project is subject to a 30% reversionary working interest that will be assigned to an unrelated third party after payout of all acquisition, operating, development, and financing costs including interest (approximately $30 million).

### *Niobrara – Colorado & Nebraska*

Our Niobrara Project is located in the northeastern portion of the D-J Basin, where we owned a 100% working interest in approximately 53,188 gross acres as of December 31, 2014. Our acreage is located in Phillips and Sedgwick Counties, Colorado, and Perkins County, Nebraska.

Approximately 21,000 acres in this project are held by production and leases on approximately 17,500 acres expire after 2015. As of December 31, 2014, we owned a 100% working interest in 24 Niobrara gas wells and we owned approximately a 6% overriding royalty interest in 180 Niobrara gas wells that are operated by Atlas Resources, LLC. All of these wells are located in Amherst Field in Phillips and Sedgwick Counties, Colorado. As of December 31, 2014, we produced approximately 215 net mcf of natural gas per day from the Niobrara formation at a depth of approximately 2,500 feet..

Our existing Niobrara acreage was high-graded based on structural features identified through analysis of 114 miles of 2D and 165 square miles (105,000 acres) of 3D seismic data on our original position of 330,000 net acres. We have identified more than 150 highly-ranked Niobrara drilling locations on our acreage based on 3D seismic analysis, which has historically yielded success rates of approximately 90% in this play. Our acreage is well situated with direct access to the Cheyenne Hub market in immediate proximity to the 1,679-mile Rocky Mountain Express pipeline and the 436-mile Trailblazer pipeline.

### *DJ Basin Resource Play Exposure*

Other operators in the DJ basin have recently permitted, drilled and tested numerous wells on trend with our Niobrara Project acreage and our Adena Field Project acreage. These operators are targeting oil production from conventional reservoirs and unconventional resource plays in Permian and Pennsylvanian aged carbonates and shales. These plays are in the early stages of exploration and development, and widespread economic success has not yet been established. We continue to monitor these exploration efforts closely and we currently own and control all depths that are prospective for these plays under all of our current acreage position.

**Our Kansas Properties**

The table below summarizes our current Kansas acreage by project name as of December 31, 2014.

| Project Name | Developed Acreage [1] | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| | Gross | Net [2] | Gross | Net [2] | Gross | Net [2] |
| Mississippian Project | 6,758 | 5,154 | 4,301 | 3,533 | 11,059 | 8,687 |
| Cherokee Project | 2,495 | 1,855 | 7,757 | 6,889 | 10,252 | 8,744 |
| Other | 584 | 146 | - | - | 584 | 146 |
| Total | 9,837 | 7,155 | 12,058 | 10,422 | 21,895 | 17,577 |

(1) Developed acreage includes all acreage that was held by production as of December 31, 2014.

(2) Net acreage is based on our net working interest as of December 31, 2014.

***Mississippian Project***

Our Mississippian Project is located in Woodson and Greenwood Counties in Southeast Kansas, where we owned a 90% working interest in 6,729 gross acres,a 70% working interest in 2,330 gross acres and a 50% working interest in 2,000 gross acres as of December 31, 2014. Approximately 73.5% of the gross leased acres in this project are currently held-by-production (see "Glossary" on page 16 for definition of held-by-production).

In December 2013, we acquired a 90% working interest in 1,280 gross acres that are adjacent to acreage that we successfully developed in 2012 and 2013. We acquired a 90% working interest in approximately 1,040 gross acres through a purchase option contained in the Joint Development Agreement with Haas Petroleum, LLC and MorMeg, LLC ("Joint Development Agreement"). Per the terms of the Joint Development Agreement, we had the right to exercise a purchase option after achieving certain capital expenditure hurdles on existing acreage. The capital expenditure hurdles were achieved in December 2013 and we exercised the purchase option for the new acreage effective December 30, 2013. In December 2013, we acquired a 90% working interest in two new leases covering approximately 240 gross acres.

On December 30, 2013, the Company entered into a Participation Agreement with MorMeg, LLC and Haas Petroleum, LLC, to drill and develop the Golden Project in Woodson County, Kansas. Pursuant to the terms of the Participation Agreement, we acquired a 70% working interest in approximately 2,330 gross acres. We drilled two wells in the Golden Project in January 2014.

As of December 31, 2014, our Mississippian Project was producing approximately 205 gross barrels of oil per day from the Mississippian formation at a depth of approximately 1,700 feet. We drilled and completed 12 new oil wells and 3 new water injection wells in this project during 2014. Water injection from some new injector wellbores commenced in late 2012, and new water injection operations were initiated throughout 2014 as additional injection wells were completed. We have experienced an initial production response on some acreage resulting from water injection, and we anticipate continued production increases during 2015 from water injection operations.

***Cherokee Project***

Our Cherokee Project is located in Miami and Franklin Counties in Eastern Kansas, where we owned an average working interest of 86% in 10,252 gross acres as of December 31, 2014. As of December 31, 2014, approximately 21% of the gross leased acres in the Cherokee Project were held by production, and we believe that numerous development drilling opportunities exist on acreage that is currently undeveloped. A number of our Cherokee leases will expire during 2016; however, a majority of the expiring leases contain 3 year extension options. We intend to selectively execute certain extension options as leases expire in 2015. As of December 31, 2014, our Cherokee Project was producing over 150 gross barrels of oil per day from the Squirrel formation at a depth of approximately 600 feet. We drilled 21 new oil wells and 16 new water injection wells in this project during 2014.

**Our Texas Properties**

The table below summarizes our current Texas acreage by project name as of December 31, 2014.

| Project Name | Developed Acreage [1] | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| | Gross | Net [2] | Gross | Net [2] | Gross | Net [2] |
| El Toro Project | 458 | 275 | - | - | 458 | 275 |
| Total | 458 | 275 | - | - | 458 | 275 |

(1) Developed acreage includes all acreage that was held by production as of December 31, 2014.
(2) Net acreage is based on our net working interest as of December 31, 2014.

***El Toro Project***

Our El Toro Project is located in Atascosa and Frio Counties in South Texas. As of December 31, 2014, we owned a 60% working interest in 458 gross acres. As of December 31, 2014, this project was producing approximately 30 gross barrels of oil per day from the Olmos formation at a depth of approximately 4,500 feet.

As a result of increasing costs in this area, we did not drill any new wells in this project in 2014 and focused 100% of our capital budget on our Kansas and Colorado properties. However, we believe the El Toro project is prospective for horizontal drilling and we intend to evaluate this potential in the future.

## Our Business Strategy

Our principal strategy focuses on the acquisition and development of oil and gas properties that have low production decline rates and offer abundant drilling opportunities with low risk profiles. Our oil and gas operations are in Kansas, Colorado, Nebraska, and Texas. The principal elements of our business strategy are:

- *Develop Our Existing Properties.* Creating production, cash flow, and reserve growth by developing our extensive inventory of hundreds of drilling locations that we have identified on our existing properties.

- *Maximize Operational Control.* We seek to operate and maintain a substantial working interest in the majority of our properties. We believe the ability to control our drilling inventory will provide us with the opportunity to more efficiently allocate capital, manage resources, control operating and development costs, and utilize our experience and knowledge of oil and gas field technologies.

- *Pursue Selective Acquisitions and Joint Ventures.* We believe our local presence in Kansas, Colorado, Nebraska, and Texas makes us well-positioned to pursue selected acquisitions and joint venture arrangements.

- *Reduce Unit Costs Through Economies of Scale and Efficient Operations.* As we increase our oil and gas production and develop our existing properties, we expect that our unit cost structure will benefit from economies of scale. In particular, we anticipate reducing unit costs by greater utilization of our existing infrastructure over a larger number of wells.

Our future financial results will continue to depend on:

- our ability to source and evaluate potential projects;

- our ability to discover commercial quantities of oil and gas;

- the market price for oil and gas;

- our ability to implement our exploration and development program, which is dependent on the availability of capital resources; and

- our ability to cost effectively manage our operations.

We cannot guarantee that we will succeed in any of these respects. Further, we cannot know if the price of crude oil and natural gas prevailing at the time of production will be at a level allowing for profitable production, or that we will be able to obtain additional funding at terms favorable to us to increase our capital resources. A detailed description of these and other risks that could materially impact our actual results is in "Risk Factors" under ITEM 1A.

## Drilling Activity

The following table sets forth the results of our drilling activities, including both oil and gas production wells and water injection wells that were drilled and completed during the year ended December 31, 2014 and the year ended December 31, 2013.

Drilling Activity

| | Gross Wells | | | Net Wells (1) | | |
|---|---|---|---|---|---|---|
| Fiscal Year | Total | Successful | Dry | Total | Successful | Dry |
| 2013 - Development | 93 | 93 | - | 75.9 | 75.9 | - |
| 2014 – Development | 52 | 51 | 1 | 41.0 | 40.1 | 0.9 |
| 2013 - Recompletion | 4 | 4 | - | 4 | 4 | - |
| 2014 - Recompletion | 19 | 19 | - | 19 | 19 | - |

(1) Net wells are based on our net working interest at the end of each respective year.

**Net Production, Average Sales Price and Average Production and Lifting Costs**

The table below sets forth our net oil and gas production (net of all royalties, overriding royalties and production due to others) for the years ended December 31, 2014 and 2013, the average sales prices, average production costs and direct lifting costs per unit of production.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Net Production | | |
| Crude oil (Bbl) | 157,089 | 114,112 |
| Natural gas (Mcf) | 325,894 | 39,135 |
| | | |
| Average Sales Prices | | |
| Crude oil (Bbl) | $ 84.40 | $ 94.86 |
| Natural gas (Mcf) | $ 3.18 | $ 3.01 |
| | | |
| Average Production Cost per BOE (1) | $ 48.78 | $ 49.34 |
| Average Lifting Costs per BOE (2) | $ 31.99 | $ 33.95 |

(1) Production costs include all operating expenses, depreciation, depletion and amortization, lease operating expenses (including price differentials) and all associated taxes. Impairment of oil and gas properties is not included in production costs.

(2) Direct lifting costs do not include impairment expense or depreciation, depletion and amortization, but do include transportation costs, which are paid to our purchasers as a price differential.

**Results of Oil and Gas Producing Activities**

The following table shows the results of operations from our oil and gas producing activities from the years ended December 31, 2014 and 2013. Results of operations from these activities have been determined using historical revenues, production costs, depreciation, depletion and amortization of the capitalized costs subject to amortization. General and administrative expenses and interest expense have been excluded from this determination.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Production revenues | $ 14,293,368 | $ 10,942,270 |
| Production costs | (6,762,248) | (4,095,850) |
| Depreciation, depletion and amortization | (3,259,442) | (1,691,008) |
| Results of operations for producing activities | $ 4,271,678 | $ 5,155,412 |

**Active Wells**

The following table sets forth the number of wells in which we owned a working interest that were actively producing oil and gas or actively injecting water as of December 31, 2014.

| | Active | |
|---|---|---|
| Project | Gross | Net (1) |
| Crude Oil | | |
| El Toro Project | 12 | 7.2 |
| Mississippian Project | 231 | 207.9 |
| Cherokee Project | 598 | 444.7 |
| Adena Field Project | 51 | 51.0 |
| Other | 40 | 35.2 |
| Total Oil | 932 | 746.0 |
| | | |
| Natural Gas | | |
| Niobrara Project | 21 | 21.0 |
| Other | 36 | 3.2 |
| Total Gas | 57 | 24.2 |

(1) Net wells are based on our net working interest as of December 31, 2014.

**Reserves**

*Proved Reserves*

The estimated total PV10 (present value) of our proved reserves as of December 31, 2014 was $64.3 million, compared to $102.4 million as of December 31, 2013. Our total net proved oil and gas reserves as of December 31, 2014 were 4.4 million BOE (69% oil), compared to 5.8 million BOE (77% oil) as of December 31, 2013. Of the 4.4 million net BOE of total proved reserves at December 31, 2014, approximately 50% are classified as proved developed producing, approximately 19% are classified as proved developed non-producing, and approximately 31% are classified as proved undeveloped. See "Glossary" on page 17 for our definition of PV10.

The estimated PV10 of the 4.4 million BOE is set forth in the following table. The PV10 is calculated using an average net oil price of $87.89 per barrel, an average net natural gas price of $2.85 per mcf and an average natural gas liquids price of $18.73 per barrel, and by applying an annual discount rate of 10% to the forecasted future net cash flow.

**Summary of Proved Oil and Gas Reserves**
**as of December 31, 2014**

| Proved Reserves Category | Gross BOE | Net BOE [1] | PV10 [2] (before tax) |
|---|---|---|---|
| Proved, Developed | 4,579,675 | 3,048,261 | 51,942,200 |
| Proved, Undeveloped | 1,754,621 | 1,351,919 | 12,376,500 |
| Total Proved | 6,334,296 | 4,400,180 | 64,318,700 |

(1) Net BOE is based upon our net revenue interest

(2) See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 34 for a reconciliation to the comparable GAAP financial measure.

**Oil and Gas Reserves Reported to Other Agencies**

We did not file any estimates of total proved net oil and gas reserves with, or include such information in reports to any federal authority or agency, other than the SEC, during the year ended December 31, 2014.

**Title to Properties**

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel or have title reviewed by professional landmen only when we acquire producing properties or before we begin drilling operations. However, any acquisition of producing properties without obtaining title opinions is subject to a greater risk of title defects.

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements and liens for current taxes and other burdens, including mineral encumbrances and restrictions. Further, our debt is secured by liens substantially on all of our assets. These burdens have not materially interfered with the use of our properties in the operation of our business to date, though there can be no assurance that such burdens will not materially impact our operations in the future

### Sale of Oil and Gas

We do not intend to refine our oil production. We expect to sell all or most of our production to a small number of purchasers in a manner consistent with industry practices at prevailing rates by means of long-term and short-term sales contracts, some of which may have fixed price components. In 2014, we sold oil to Coffeyville Resources, Plains Marketing LP, and Sunoco, Inc. on a month-to-month basis (i.e., without a long-term contract). We sold our natural gas to United Energy Trading on a month-to-month basis and Western Operating Company under a long-term contract. We also have an ISDA master agreement and a fixed price swap with BP and with Cargill through December 31, 2015. Under current conditions, we should be able to find other purchasers, if needed. All of our produced oil is held in tank batteries. Each respective purchaser picks up the oil from our tank batteries and transports it by truck to refineries. In addition, our Board of Directors has implemented a crude oil and gas hedging strategy that will allow management to hedge the majority of our net production in an effort to mitigate our exposure to changing oil and natural gas prices in the intermediate term.

### Secondary Recovery and Other Production Enhancement Strategies

When an oil field is first produced, the oil typically is recovered as a result of natural pressure within the producing formation, often assisted by pumps of various types. The only natural force present to move the crude oil to the wellbore is the pressure differential between the higher pressure in the formation and the lower pressure in the wellbore. At the same time, there are many factors that act to impede the flow of crude oil, depending on the nature of the formation and fluid properties, such as pressure, permeability, viscosity and water saturation. This stage of production is referred to as "primary production”, which typically only recovers 5% to 15% of the crude oil originally in place in a producing formation.

Production from oil fields can often be enhanced through the implementation of "secondary recovery", also known as waterflooding, which is a method in which water is injected into the reservoir through injector wells in order to maintain or increase reservoir pressure and push oil to the adjacent producing wellbores. We utilize waterflooding as a secondary recovery technique for the majority of our oil properties in Kansas, even in the early stages of production and we use a secondary recovery technique in parts of the Adena Field Project in Colorado.

As a waterflood matures over time, the fluid produced contains increasing amounts of water and decreasing amounts of oil. Surface equipment is used to separate the produced oil from water, with the oil going to holding tanks for sale and the water being re-injected into the oil reservoir.

In addition, we may utilize 3D seismic analysis, horizontal drilling, and other technologies and production techniques to improve drilling results and oil recovery, and to ultimately enhance our production and returns. We also believe use of such technologies and production techniques in exploring for, developing, and exploiting oil properties will help us reduce drilling risks, lower finding costs and provide for more efficient production of oil from our properties.

### Markets and Marketing

The oil and gas industry has experienced dramatic price volatility in recent years. As a commodity, global oil prices respond to macro-economic factors affecting supply and demand. In particular, world oil prices have risen and fallen in response to political unrest and supply uncertainty in the Middle East, and changing demand for energy in rapidly growing economies, notably India and China. North American prospects have become more attractive as oil prices have risen and as efforts to stimulate the US economy and reduce dependence on foreign oil have increased. Escalating conflicts in the Middle East and the ability of OPEC to control supply and pricing are some of the factors impacting the availability of global supply. As a commodity, natural gas prices respond mainly to regional supply and demand imbalances. Factors that affect the supply side include production of natural gas, levels of natural gas imports and fluctuations in underground storage. Factors that affect the demand side include peak demand brought on by winter heating and summer cooling requirements and increasing demand from the petrochemical industry for their produced products such as plastics, fertilizers, paints, soaps etc. The costs of steel and other products used to construct drilling rigs and pipeline infrastructure, as well as, drilling and well-servicing rig rates, are impacted by the commodity price volatility.

Our market is affected by many factors beyond our control, such as the availability of other domestic production, commodity prices, the proximity and capacity of oil and gas pipelines, and general fluctuations of global and domestic supply and demand. We have currently entered into month-to-month sales contracts with Coffeeville Resources, Plains Marketing LP, and Sunoco, Inc., United Energy Trading, and Western Operating Company and we do not anticipate difficulty in finding additional sales opportunities, as and when needed.

Oil and gas sales prices are negotiated based on factors such as the spot price or posted price for oil and gas, price regulations, regional price variations, hydrocarbon quality, distances from wells to pipelines, well pressure, and estimated reserves. Many of these factors are outside our control. Oil and gas prices have historically experienced high volatility, related in part to ever-changing perceptions within the industry of future supply and demand.

**Competition**

The oil and gas industry is intensely competitive and we must compete against larger companies that may have greater financial and technical resources than we do and substantially more experience in our industry. These competitive advantages may better enable our competitors to sustain the impact of higher exploration and production costs, oil and gas price volatility, productivity variances between properties, overall industry cycles and other factors related to our industry. Their advantage may also negatively impact our ability to acquire prospective properties, develop reserves, attract and retain quality personnel and raise capital.

**Research and Development Activities**

We have not spent a material amount of time or money on research and development activities in the last two years.

**Governmental Regulations**

Our oil and gas exploration, production and related operations, when developed, are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies that impose requirements relating to the exploration and production of oil and natural gas. For example, laws and regulations often address conservation matters, including provisions for the unitization or pooling of oil and gas properties, the spacing, plugging and abandonment of wells, rates of production, water discharge, prevention of waste, and other matters. Prior to drilling, we are often required to obtain permits for drilling operations, drilling bonds and file reports concerning operations. Failure to comply with any such rules and regulations can result in substantial penalties. Moreover, laws and regulations may place burdens from previous operations on current lease owners that can be significant.

The public attention on the production of oil and gas will most likely increase the regulatory burden on our industry and increase the cost of doing business, which may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations.

The price we may receive from the sale of oil and gas will be affected by the cost of transporting products to markets. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil and gas pipelines, which, generally, would index such rates to inflation, subject to certain conditions and limitations. We are not able to predict with certainty the effect, if any, of these regulations on our intended operations. However, the regulations may increase transportation costs or reduce well head prices for oil and natural gas.

**Environmental Matters**

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue.

These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;
- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from its operations, or due to previous operations conducted on any leased lands.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil and gas field wastes as "non-hazardous", such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements.

The Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act"), and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. These laws also regulate the discharge of storm water in process areas. Pursuant to these laws and regulations, we are required to obtain and maintain approvals or permits for the discharge of wastewater and storm water and develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans", in connection with on-site storage of greater than threshold quantities of oil and gas. The EPA issued revised SPCC rules in July 2002 whereby SPCC plans are subject to more rigorous review and certification procedures. We believe that our operations are in substantial compliance with applicable Clean Water Act and analogous state requirements, including those relating to wastewater and storm water discharges and SPCC plans.

The Endangered Species Act, as amended ("ESA"), seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of the Act. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations will be in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject us to significant expenses to modify our operations or could force us to discontinue certain operations altogether.

**Personnel**

We currently have 29 full-time employees, including field personnel. As production and drilling activities increase or decrease, we may have to continue to adjust our technical, operational and administrative personnel as appropriate. We are using and will continue to use independent consultants and contractors to perform various professional services, particularly in the area of land services, reservoir engineering, geology, drilling, water hauling, pipeline construction, well design, well-site monitoring and surveillance, permitting and environmental assessment. We believe that this use of third-party service providers may enhance our ability to contain operating and general expenses, and capital costs.

**Facilities**

We currently lease our executive offices at 4040 Broadway, Suite 508, San Antonio, Texas 78209, under a lease which expires November 2017. We also have field offices located at 3881 Rock Creek Rd, Rantoul, Kansas 66069 and 165 South Union Blvd, Suite 410, Lakewood Colorado 80228. We had corporate office space under lease at 27 Corporate Woods, Suite 350, 10975 Grandview Drive, Overland Park, Kansas 66210 that expired September 30, 2013.

## GLOSSARY

| Term | Definition |
|---|---|
| Barrel (Bbl) | The standard unit of measurement of liquids in the petroleum industry, it contains 42 U.S. standard gallons. Abbreviated to "bbl". |
| Basin | A depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. Sedimentary basins vary from bowl-shaped to elongated troughs. Basins can be bounded by faults. Rift basins are commonly symmetrical; basins along continental margins tend to be asymmetrical. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, then a petroleum system can develop within the basin. |
| BOE | Abbreviation for a barrel of oil equivalent and is a term used to summarize the amount of energy that is equivalent to the amount of energy found in a barrel of crude oil. On a BTU basis 6,000 cubic feet of natural gas is the energy equivalent to one barrel of crude oil. A conversion ratio of 6:1 is used to convert natural gas measured in thousands of cubic feet into an equivalent barrel of oil. |
| BOPD | Abbreviation for barrels of oil per day, a common unit of measurement for volume of crude oil. The volume of a barrel is equivalent to 42 U.S. standard gallons. |
| Carried Working Interest | The owner of this type of working interest in the drilling of a well incurs no capital contribution requirement for drilling or completion costs associated with a well and, if specified in the particular contract, may not incur capital contribution requirements beyond the completion of the well. |
| Completion/Completing | The activities and methods of preparing a well for the production of oil and gas or for other purposes such as injection. |
| Development | The phase in which a proven oil or natural gas field is brought into production by drilling development wells. |
| Development Drilling | Wells drilled during the Development phase. |
| Division Order | A directive signed by all owners verifying to the purchaser or operator of a well the decimal interest of production owned by the royalty owner and other working interest owners. The Division Order generally includes the decimal interest, a legal description of the property, the operator's name, and several legal agreements associated with the process. Completion of this step generally precedes placing the royalty owner or working interest owner on pay status to begin receiving revenue payments. |
| Drilling | Act of boring a hole through which oil and natural gas may be produced. |
| Dry Wells | A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes. |
| Exploration | The phase of operations which covers the search for oil and gas generally in unproven or semi-proven territory. |

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| Exploratory Drilling | Drilling of a relatively high percentage of properties which are unproven. |
| Farm Out | An arrangement whereby the owner of a lease assigns all or some portion of the lease or licenses to another company for undertaking exploration or development activity. |
| Fixed Price Swap | A derivative instrument that exchanges or "swaps" the "floating" or daily price of a specified volume of oil or natural gas over a specified period, for a fixed price for the specified volume over the same period (typically three months or longer). |
| Gross Acre | The number of acres in which the Company owns any working interest. |
| Gross Producing Well | A well in which a working interest is owned and is producing oil or gas. The number of gross producing wells is the total number of wells producing oil or gas in which a working interest is owned. |
| Gross Well | A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. |
| Held-By-Production (HBP) | Refers to an oil and gas property under lease, in which the lease continues to be in force, because of production from the property. |
| Horizontal drilling | A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then turned and drilled horizontally. Horizontal drilling allows the wellbore to follow the desired formation. |
| In-Fill Wells | In-fill wells refers to wells drilled between established producing wells; a drilling program to reduce the spacing between wells in order to increase production and recovery of in-place hydrocarbons. |
| Oil and Gas Lease | A legal instrument executed by a mineral owner granting the right to another to explore, drill, and produce subsurface oil and gas. An oil and gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee. |
| Lifting Costs | The expenses of producing oil and gas from a well. Lifting costs are the operating costs of the wells including the gathering and separating equipment. Lifting costs do not include the costs of drilling and completing the wells or transporting the oil and gas. |
| MCF | An abbreviation for one thousand cubic feet of natural gas. |
| Net Acres | Determined by multiplying gross acres by the working interest that the Company owns in such acres. |
| Net Producing Wells | The number of producing wells multiplied by the working interest in such wells. |
| Net Revenue Interest | A share of production revenues after all royalties, overriding royalties and other non-operating interests have been taken out of production for a well(s). |
| Operator | A person, acting for itself, or as an agent for others, designated to conduct the operations on its or the joint interest owners' behalf. |

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|---|---|
| Overriding Royalty | Ownership in a percentage of production or production revenues, free of the cost of production, created by the lessee, company and/or working interest owner and paid by the lessee, company and/or working interest owner out of revenue from the well. |
| Probable Reserves | Probable reserves are additional reserves that are less certain to be recovered than proved reserves but which, together with Proved reserves, are as likely as not to be recovered. |
| Proved Developed Reserves | Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. This definition of proved developed reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. |
| Proved Developed Non-Producing | Proved developed reserves expected to be recovered from zones behind casings in existing wells or from future production increases resulting from the effects of waterflood operations. |
| Proved Reserves | Proved reserves are estimated quantities of crude oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. |
| Proved Undeveloped Reserves | Proved undeveloped reserves are the portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. |
| PV10 | PV10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV10 is a non-GAAP financial measure. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" on page 33 for a reconciliation to the comparable GAAP financial measure. |
| Reactivation | After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well’s productivity. |
| Recompletion | Completion of an existing well for production from one formation or reservoir to another formation or reservoir that exists behind casing of the same well. |
| Reservoir | The underground rock formation where oil and gas has accumulated. It consists of a porous rock to hold the oil and gas, and a cap rock that prevents its escape. |

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|---|---|
| Secondary Recovery | The stage of hydrocarbon production during which an external fluid such as water or natural gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are natural gas injection and waterflooding. Normally, natural gas is injected into the natural gas cap and water is injected into the production zone to sweep oil and gas from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form of enhanced recovery. |
| Stock Tank Barrel or STB | A stock tank barrel of oil and gas is the equivalent of 42 U.S. Gallons at 60 degrees Fahrenheit. |
| Undeveloped Acreage | Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves. |
| Unitize, Unitization | When owners of oil and gas reservoir pool their individual interests in return for an interest in the overall unit. |
| Waterflood | The injection of water into an oil and gas reservoir to "push" additional oil and gas out of the reservoir rock and into the wellbores of producing wells. Typically a secondary recovery process. |
| Water Injection Wells | A well in which fluids are injected rather than produced, the primary objective typically being to maintain or increase reservoir pressure, often pursuant to a waterflood. |
| Water Supply Wells | A well in which fluids are being produced for use in a water injection well. |
| Wellbore | A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open. Also called a borehole or hole. |
| Working Interest | An interest in an oil and gas lease entitling the owner to receive a specified percentage of the proceeds of the sale of oil and gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and gas. |

## ITEM 1A. RISK FACTORS.

In the course of conducting our business operations, we are exposed to a variety of risks that are inherent to the oil and gas industry. The following discusses some of the key inherent risk factors that could affect our business and operations. Other factors besides those discussed below or elsewhere in this report also could adversely affect our business and operations, and these risk factors should not be considered a complete list of potential risks that may affect us.

### Risks Related to Recent Developments

***Our 2014 oil and gas reserve report shows a material decline in our estimated reserves, which will have adverse implications to our business.***

Our 2014 oil and gas reserve report shows a material decline in our estimated reserves. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For example, estimates of quantities of proved reserves and their PV10 value are affected by changes in crude oil and gas prices, because estimates are based on prevailing prices at the time of their determination. Further, reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary from one another.

The reduction in our reserve estimates is likely to change the schedule of future production and development drilling that was contemplated in our 2013 reserve report. Reserve estimates are generally different, and often materially so, from the quantities of oil and natural gas that are ultimately recovered. Furthermore, estimates of quantities of proved reserves and their PV10 value may be affected by changes in crude oil and gas prices because the Company’s estimates are based on prevailing prices at the time of their determination.

***Our 2014 oil and gas report has caused a material reduction in our borrowing base under our revolving credit facility, resulting in us being overdrawn on our credit facilities.***

Our maximum borrowings under our credit facility are subject to reduction based upon a borrowing base calculation, which is re-determined using updated reserve reports. Because our 2014 reserve report shows a material reduction in reserves as discussed above, our borrowing base will be similarly reduced. Such a reduction could show that we are overdrawn on our credit facilities and therefore not in compliance with the financial covenants imposed by our lenders.

If this occurs our lenders may impose a plan requiring that we reduce the amount of that overdraft. Any such plan may include an adjustment in the interest rate on our secured credit facilities and a requirement for regular amortizing payments. Any such plan would likely require, among other things, that we apply our net cash flow to repayment of the principal of our secured credit facilities, limit our ability to pay our ordinary operating expenses as they become due, limit our new production activities, and may require that we suspend payment of dividends on our series A preferred stock. All of those factors will adversely affect the results of our operations and our stock price.

***Current volatile market conditions and significant fluctuations in energy prices may continue indefinitely, negatively affecting our business prospects and viability.***

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our planned operations and financial condition. The amount of any royalty payment we receive, if any, from the production of oil and gas from our oil and gas interests will depend on numerous factors beyond our control.

***Declining economic conditions and worsening geopolitical conditions could negatively impact our business.***

Our operations are affected by local, national and worldwide economic conditions. Markets in the United States and elsewhere have been experiencing volatility and disruption for more than 5 years, due in part to the financial stresses affecting the liquidity of the banking system and the financial markets generally. The consequences of a potential or prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets.

In addition, actual and attempted terrorist attacks in the United States, Middle East, Southeast Asia and Europe, and war or armed hostilities in the Middle East, the Persian Gulf, North Africa, Iran, North Korea or elsewhere, or the fear of such events, could further exacerbate the volatility and disruption to the financial markets and economy.

While the ultimate outcome and impact of the current economic conditions cannot be predicted, a lower level of economic activity might result in a decline in energy consumption, which may materially adversely affect the price of oil and gas, our revenues, liquidity and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital.

***The oil and natural gas business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.***

Our development, exploitation and exploration activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their cost, unsuccessful wells can hurt our efforts to replace reserves.

The oil and natural gas business involves a variety of operating risks, including:

- unexpected operational events and/or conditions;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- oil and gas quality issues;
- pipe, casing, cement or pipeline failures;
- natural disasters;
- fires, explosions, blowouts, surface cratering, pollution and other risks or accidents;
- environmental hazards, such as oil spills, pipeline ruptures and discharges of toxic gases;
- compliance with environmental and other governmental requirements; and
- uncontrollable flows of oil or natural gas or well fluids.

If we experience any of these problems, it could affect well bores, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Because we use third-party drilling contractors to drill our wells, we may not realize the full benefit of worker compensation laws in dealing with their employees. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could impact our operations enough to force us to cease our operations.

***Oil and gas prices are volatile. Future volatility may cause negative change in cash flows which may result in our inability to cover our operating or capital expenditures.***

Our future revenues, profitability, future growth and the carrying value of our properties depend substantially on the prices we may realize for our oil and gas production. Our realized prices may also affect the amount of cash flow available for operating or capital expenditures and our ability to borrow and raise additional capital.

Oil and gas prices are subject to wide fluctuations in response to relatively minor changes in or perceptions regarding supply and demand. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause this volatility are:

- commodities speculators;
- local, national and worldwide economic conditions;
- worldwide or regional demand for energy, which is affected by economic conditions;
- the domestic and foreign supply of oil and gas;
- weather conditions;
- natural disasters;
- acts of terrorism;
- domestic and foreign governmental regulations and taxation;
- political and economic conditions in oil and gas producing countries, including those in the Middle East and South America;
- impact of the U.S. dollar exchange rates on oil and gas prices;
- the availability of refining capacity;
- actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state controlled oil and gas companies relating to oil and gas price and production controls; and
- the price and availability of other fuels.

It is impossible to predict oil and gas price movements with certainty. A drop in oil and gas prices may not only decrease our future revenues on a per unit basis but also may reduce the amount of oil and gas that we can produce economically. A substantial or extended decline in oil and gas prices would materially and adversely affect our future business enough to potentially force us to cease our business operations. In addition, our reserves, financial condition, results of operations, liquidity and ability to finance and execute planned capital expenditures will also suffer in such a price decline.

***Approximately 31% of our total proved reserves as of December 31, 2014 consist of undeveloped reserves, and those reserves may not ultimately be developed or produced.***

Our estimated total proved PV10 (present value) before tax of reserves as of December 31, 2014 was $64.3 million, versus $102.4 million as of December 31, 2013. Of the 4.4 million BOE of total proved reserves, approximately 50% are classified as proved developed producing, approximately 19% are classified as proved developed non-producing, and approximately 31% are classified as proved undeveloped.

Assuming we can obtain adequate capital resources, we plan to develop and produce all of our proved reserves, but ultimately some of these reserves may not be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be produced in the time periods we have planned, at the costs we have budgeted, or at all.

***Because we face uncertainties in estimating proved recoverable reserves, you should not place undue reliance on such reserve information.***

Our reserve estimates and the future net cash flows attributable to those reserves at December 31, 2014 were prepared by MHA Petroleum Consultants LLC, an independent petroleum consultant. There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of these independent consultants and engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that can be economically extracted, which cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of the available data, assumptions regarding future oil and gas prices, expenditures for future development and exploitation activities, and engineering and geological interpretation and judgment. Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and oil and gas prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and value of cash flows from those reserves may vary significantly from the assumptions and estimates in our reserve reports. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classification of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves included in this report were prepared by MHA Petroleum Consultants LLC in accordance with rules of the Securities and Exchange Commission, or SEC, and are not intended to represent the fair market value of such reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs. However, actual future net cash flows from our oil and gas properties also will be affected by factors such as:

- geological conditions;
- assumptions governing future oil and gas prices;
- amount and timing of actual production;
- availability of funds;
- future operating and development costs;
- actual prices we receive for oil and gas;
- changes in government regulations and taxation; and
- capital costs of drilling new wells

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our business or the oil and gas industry in general.

***The differential between the New York Mercantile Exchange, or NYMEX, or other benchmark price of oil and gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.***

The prices that we receive for our oil production in Texas, Colorado and Kansas are typically based on a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The prices we receive for our natural gas production in Colorado is based upon local market conditions but generally we receive a discount to Henry Hub. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and gas differentials. In recent years for example, production increases from competing North American producers, in conjunction with limited refining and pipeline capacity have widened this differential. Recent economic conditions, including volatility in the price of oil and gas, have resulted in both increases and decreases in the differential between the benchmark price for oil and gas and the wellhead price we receive. These fluctuations could have a material adverse effect on our results of operations, financial condition and cash flows by decreasing the proceeds we receive for our oil and gas production in comparison to what we would receive if not for the differential.

***The oil and gas business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.***

Our development, exploitation and exploration activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil and gas well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their cost, unsuccessful wells can hurt our efforts to replace reserves.

The oil and gas business involves a variety of operating risks, including:

- unexpected operational events and/or conditions;
- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- adverse weather conditions;
- facility or equipment malfunctions;

- title problems;
- oil and gas quality issues;
- pipe, casing, cement or pipeline failures;
- natural disasters;
- fires, explosions, blowouts, surface cratering, pollution and other risks or accidents;
- environmental hazards, such as oil spills, pipeline ruptures and discharges of toxic gases;
- compliance with environmental and other governmental requirements; and
- uncontrollable flows of oil and gas or well fluids

If we experience any of these problems, it could affect well bores, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations

Because we use third-party drilling contractors to drill our wells, we may not realize the full benefit of worker compensation laws in dealing with their employees. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could impact our operations enough to force us to cease our operations.

***Drilling wells is speculative, and any material inaccuracies in our forecasted drilling costs, estimates or underlying assumptions will materially affect our business.***

Developing and exploring for oil and gas involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oil and gas field equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil and gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. Substantially all of our wells drilled through December 31, 2014 have been development wells. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economic. Our initial drilling and development sites, and any potential additional sites that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

Development of our reserves, when established, may not occur as scheduled and the actual results may not be as anticipated. Drilling activity and lack of access to economically acceptable capital may result in downward adjustments in reserves or higher than anticipated costs. Our estimates will be based on various assumptions, including assumptions over which we have control and assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. We have control over our operations that affect, among other things, acquisitions and dispositions of properties, availability of funds, use of applicable technologies, hydrocarbon recovery efficiency, drainage volume and production decline rates that are part of these estimates and assumptions and any variance in our operations that affects these items within our control may have a material effect on reserves. The process of estimating our oil and gas reserves is extremely complex, and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Our estimates may not be reliable enough to allow us to be successful in our intended business operations. Our actual production, revenues, taxes, development expenditures and operating expenses will likely vary from those anticipated. These variances may be material.

***Unless we replace our oil and gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.***

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and gas production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

***In order to exploit successfully our current oil and gas leases and others that we acquire in the future, we will need to generate significant amounts of capital.***

The oil and gas exploration, development and production business is a capital-intensive undertaking. In order for us to be successful in acquiring, investigating, developing, and producing oil and gas from our current mineral leases and other leases that we may acquire in the future, we will need to generate an amount of capital in excess of that generated from our results of operations. In order to generate that additional capital, we may need to obtain an expanded debt facility and issue additional shares of our equity securities. There can be no assurance that we will be successful in either obtaining that expanded debt facility or issuing additional shares of our equity securities, and our inability to generate the needed additional capital may have a material adverse effect on our prospects and financial results of operations. If we are able to issue additional equity securities in order to generate such additional capital, then those issuances may occur at prices that represent discounts to our trading price, and will dilute the percentage ownership interest of those persons holding our shares prior to such issuances. Unless we are able to generate additional enterprise value with the proceeds of the sale of our equity securities, those issuances may adversely affect the value of our shares that are outstanding prior to those issuances.

***A significant portion of our potential future reserves and our business plan depend upon secondary recovery techniques to establish production. There are significant risks associated with such techniques.***

We anticipate that a significant portion of our future reserves and our business plan will be associated with secondary recovery projects that are either in the early stage of implementation or are scheduled for implementation subject to availability of capital. We anticipate that secondary recovery will affect our reserves and our business plan, and the exact project initiation dates and, by the very nature of waterflood operations, the exact completion dates of such projects are uncertain. In addition, the reserves and our business plan associated with these secondary recovery projects, as with any reserves, are estimates only, as the success of any development project, including these waterflood projects, cannot be ascertained in advance. If we are not successful in developing a significant portion of our reserves associated with secondary recovery methods, then the project may be uneconomic or generate less cash flow and reserves than we had estimated prior to investing the capital. Risks associated with secondary recovery techniques include, but are not limited to, the following:

- higher than projected operating costs;
- lower-than-expected production;
- longer response times;
- higher costs associated with obtaining capital;
- unusual or unexpected geological formations;
- fluctuations in oil and gas prices;
- regulatory changes;
- shortages of equipment; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect our financial condition or results of operations.

***Any acquisitions we complete are subject to considerable risk.***

Even when we make acquisitions that we believe are good for our business, all acquisitions involve potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a decrease in our liquidity by using our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;

- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage the acquired properties or assets;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic or geological areas; and
- customer or key employee losses at the acquired businesses.

***Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often incomplete or inconclusive.***

Our reviews of acquired properties can be inherently incomplete because it is not always feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, plugging or orphaned well liability are not necessarily observable even when an inspection is undertaken.

***We must obtain governmental permits and approvals for drilling operations, which can result in delays in our operations, be a costly and time consuming process, and result in restrictions on our operations.***

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuances in the regions in which we operate. Compliance with the requirements imposed by these authorities can be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations and/or fines. Regulatory or legal actions in the future may materially interfere with our operations or otherwise have a material adverse effect on us. In addition, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that a proposed project may have on the environment, threatened and endangered species, and cultural and archaeological artifacts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

***Due to our lack of geographic diversification, adverse developments in our operating areas would materially affect our business.***

We currently only lease and operate oil and gas properties located in Colorado, Nebraska, Kansas and Texas. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these properties caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, adverse weather conditions or other events which impact this area.

***We depend on a small number of customers for all, or a substantial amount of our sales. If these customers reduce the volumes of oil and gas they purchase from us, our revenue and cash flow will decline to the extent we are not able to find new customers for our production.***

We currently sell oil to two purchasers in Kansas: Coffeyville Resources and Plains Marketing, LP. There are approximately five potential purchasers of oil in Kansas. If a key purchaser were to reduce the volume of oil it purchases from us, our revenue and cash available for operations will decline to the extent we are not able to find new customers to purchase our production at equivalent prices.

We currently sell oil to Sunoco, Inc. in Texas. There are numerous purchasers in Texas, but increased production volumes from extensive shale drilling activity in the area may result in reduced purchases by several of our purchasers.

We currently sell oil to Plains Marketing, LP in Colorado. There are a number of potential purchasers of our oil in Colorado but increased production volumes from the DJ basin may result in reduced purchases by our purchasers. If a key purchaser were to reduce the volume of oil it purchases from us, our revenue and cash available for operations will decline to the extent we are not able to find new customers to purchase our production at equivalent prices.

We sell natural gas to United Energy Trading and Western Operating Company in Colorado. There are other purchasers for our natural gas in Colorado. If a key purchaser were to reduce the volume of gas it purchases from us, our revenue and cash available for operations will decline to the extent we are not able to find new customers to purchase our production at equivalent prices.

***We are not the operator of some of our properties and we have limited control over the activities on those properties.***

We are not the operator of our Mississippian Project, and our dependence on the operator of this project limits our ability to influence or control the operation or future development of this project. Such limitations could materially adversely affect the realization of our targeted returns on capital related to exploration, drilling or production activities and lead to unexpected future costs.

***We may suffer losses or incur liability for events for which we or the operator of a property have chosen not to obtain insurance.***

Our operations are subject to hazards and risks inherent in producing and transporting oil and gas, such as fires, natural disasters, explosions, pipeline ruptures, spills, and acts of terrorism, all of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our and others' properties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. In addition, pollution and environmental risks generally are not fully insurable. As a result of market conditions, existing insurance policies may not be renewed and other desirable insurance may not be available on commercially reasonable terms, if at all. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

***Our hedging activities could result in financial losses or could reduce our available funds or income and therefore adversely affect our financial position.***

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and gas, we have entered into derivative contracts through June 30, 2016 for approximately 175,000 barrels of crude oil. The settlement of and the mark to market of these contracts could result in both realized and unrealized hedging losses. For the year ended December 31, 2014, we incurred realized and unrealized gains of approximately $5,000,000. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we may utilize may be based on posted market prices, which may differ significantly from the actual crude oil prices we realize in our operations.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial 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 or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our derivative 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. In addition, while we believe our existing derivative activities are with creditworthy counterparties, deterioration in the credit markets may cause a counterparty not to perform its obligation under the applicable derivative instrument or impact their willingness to enter into future transactions with us. If that occurred, then any hedging arrangement with such counterparty would not provide any effective hedge against changes in market conditions.

***Our business depends in part on processing facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and gas production and could harm our business.***

The marketability of our oil and gas production will depend in part on the availability, proximity and capacity of pipelines and oil and gas processing facilities. The amount of oil and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we will be provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in pipeline capacity or the capacity of processing facilities could significantly reduce our ability to market our oil and gas production and could materially harm our business.

***Cost and availability of drilling rigs, equipment, supplies, personnel and other services could adversely affect our ability to execute on a timely basis our development, exploitation and exploration plans.***

Shortages or an increase in cost of drilling rigs, equipment, supplies or personnel could delay or interrupt our operations, which could impact our financial condition and results of operations. Drilling activity in the geographic areas in which we conduct drilling activities may increase, which would lead to increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in these areas may also decrease the availability of rigs. We do not have any contracts for drilling rigs and drilling rigs may not be readily available when we need them. Drilling and other costs may increase further and necessary equipment and services may not be available to us at economical prices.

***Our exposure to possible leasehold defects and potential title failure could materially adversely impact our ability to conduct drilling operations.***

We obtain the right and access to properties for drilling by obtaining oil and gas leases either directly from the hydrocarbon owner, or through a third party that owns the lease. The leases may be taken or assigned to us without title insurance. There is a risk of title failure with respect to such leases, and such title failures could materially adversely impact our business by causing us to be unable to access properties to conduct drilling operations.

***Our reserves are subject to the risk of depletion because many of our leases are in mature fields that have produced large quantities of oil and gas to date.***

A significant portion of our operations are located in or near established fields in Colorado, Nebraska, Kansas and Texas. As a result, many of our leases are in, or directly offset, areas that have produced large quantities of oil and gas to date. As such, our reserves may be negatively impacted by offsetting wells or previously drilled wells, which could significantly harm our business.

***Our lease ownership may be diluted due to financing strategies we may employ in the future.***

To accelerate our development efforts we may take on working interest partners who will contribute to the costs of drilling and completion operations and then share in any cash flow derived from production. In addition, we may in the future, due to a lack of capital or other strategic reasons, establish joint venture partnerships or farm out all or part of our development efforts. These economic strategies may have a dilutive effect on our lease ownership and could significantly reduce our operating revenues.

***We may face lease expirations on leases that are not currently held-by-production.***

We have numerous leases that are not currently held-by-production, some of which have near term lease expirations and are likely to expire. Although we believe that we can maintain our most desirable leases by conducting drilling operations or by negotiating lease extensions, we can make no guarantee that we can maintain these leases.

***We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.***

Development, production and sale of oil and gas in the United States are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include, but are not limited to:

- location and density of wells;
- the handling of drilling fluids and obtaining discharge permits for drilling operations;
- accounting for and payment of royalties on production from state, federal and Indian lands;
- bonds for ownership, development and production of oil and gas properties;
- transportation of oil and gas by pipelines;
- operation of wells and reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil and gas spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations enough to possibly force us to cease our business operations.

***Our operations may expose us to significant costs and liabilities with respect to environmental, operational safety and other matters.***

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and gas production activities. We may also be exposed to the risk of costs associated with Kansas Corporation Commission, the Texas Railroad Commission and the State of Colorado Oil and Gas Conservation Commission requirements to plug orphaned and abandoned wells on our oil and gas leases from wells previously drilled by third parties. In addition, we may indemnify sellers or lessors of oil and gas properties for environmental liabilities they or their predecessors may have created. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs, liens and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to operate effectively could be adversely affected.

***We operate in a highly competitive environment and our competitors may have greater resources than do we.***

The oil and gas industry is intensely competitive and we compete with other companies, many of which are larger and have greater financial, technological, human and other resources. Many of these companies not only explore for and produce crude oil and gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. Such companies may be able to pay more for productive oil and gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may have a greater ability to continue exploration activities during periods of low oil and gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete, our operating results and financial position may be adversely affected.

***We may incur substantial write-downs of the carrying value of our oil and gas properties, which would adversely impact our earnings.***

We review the carrying value of our oil and gas properties under the full cost method of accounting. Under the full cost method of accounting, the net book value of oil and gas properties, less deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is (a) the present value of future net revenues computed by applying current prices of oil & gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil & gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of 10 percent and assuming continuation of existing economic conditions *plus* (b) the cost of properties not being amortized *plus* (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized *less* (d) income tax effects related to differences between book and tax basis of properties. Future cash outflows associated with settling accrued retirement obligations are excluded from the calculation. Estimated future cash flows are calculated using end-of-period costs and an un-weighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months held flat for the life of the production, except where prices are defined by contractual arrangements.

Revisions to estimates of oil and gas reserves and/or an increase or decrease in current prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value of proved oil and gas properties, less related deferred income taxes, over the ceiling is charged to expense and reflected as additional depreciation, depletion, and amortization in the statement of operations.

During the years ended December 31, 2014 and 2013 there were no impairments resulting from the quarterly ceiling tests.

**Risks Associated with our Debt Financing**

***Significant and prolonged declines in commodity prices may negatively impact our borrowing base and our ability to borrow overall.***

Our borrowing base, which is based on our oil and gas reserves and is subject to review and adjustment on a semi-annual basis and other interim adjustments, may be reduced when it is reviewed. A reduction in our base results in a "loan excess" which is required to be eliminated through payment of a portion of the loan and/or cash collateralization of Letters of Credit obligations; or adding properties to the borrowing base sufficient to offset the "loan excess". A reduction in our borrowing base or the ability to borrow under our Credit Facility, combined with a reduction in cash flow from operations resulting from a decline in oil and gas prices, would likely require us to further reduce our capital expenditures and our operating activities.

***Until we repay the full amount of our outstanding Credit Facility, we may continue to have substantial indebtedness, which is secured by substantially all of our assets.***

On December 31, 2014, we had $23,000,000 of bank loans outstanding. If we defaulted on our obligations with respect to the secured debt, the lenders may enforce their rights as secured parties and we may lose all or a portion of our assets or be forced to materially reduce our business activities.

***Our substantial indebtedness could make it more difficult for us to fulfill our obligations under our Credit Facility and, therefore, adversely affect our business.***

On August 15, 2014, the Company entered into an Eighth Amendment to the Amended and Restated Credit Agreement. The Eighth Amendment reflects the following changes: (i) increased the Borrowing Base from $38,000,000 to $40,000,000; (ii) extended the maturity of the facility by three years to October 3, 2018.

As of December 31, 2014, we had total indebtedness of $23,000,000 under the Credit Facility. Our substantial indebtedness, and the related interest expense, could have important consequences to us, including:

- our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our business strategy, or other general corporate purposes;

- being forced to use cash flow to reduce our outstanding balance as a result of an unfavorable borrowing base redetermination;
- our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage as compared to our competitors that have less leverage;
- our ability to capitalize on business opportunities and to react to competitive pressures and changes in government regulation;
- our ability to, or increasing the cost of, refinancing our indebtedness; and
- our ability to enter into marketing, hedging, optimization and trading transactions by reducing the number of counterparties with whom we can enter into such transactions as well as the volume of those transactions.

***The covenants in our Credit Facility impose significant operating and financial restrictions on us.***

The Credit Facility imposes significant operating and financial restrictions on us. These restrictions limit our ability and the ability of our subsidiaries, among other things, to:

- incur additional indebtedness and provide additional guarantees;
- pay dividends and make other restricted payments;
- create or permit certain liens;
- use the proceeds from the sales of our oil and gas properties;
- use the proceeds from the unwinding of certain financial hedges;
- engage in certain transactions with affiliates; and
- consolidate, merge, sell or transfer all or substantially all of our assets or the assets of our subsidiaries.

The Credit Facility also contains various affirmative covenants with which we are required to comply. We were in compliance with these covenants as of December 31, 2014. We may be unable to comply with some or all of these covenants in the future. If we do not comply with these covenants and are unable to obtain waivers from our lenders, we would be unable to make additional borrowings under these facilities; our indebtedness under these agreements would be in default and repayment of debt could be accelerated by our lenders. If our indebtedness is accelerated, we may not be able to repay our indebtedness or borrow sufficient funds to refinance it. In addition, if we incur additional indebtedness in the future, we may be subject to additional covenants, which may be more restrictive than those to which we are currently subject.

**Risks Associated with our Common Stock**

***We do not expect to pay dividends to holders of our common stock because of the terms of our debt facility, and our need to reinvest cash flow from operations in our business.***

It is unlikely that we will pay any dividends to the holders of our common stock in the foreseeable future. The terms of our debt facility require that the lender approve any such distributions, and the lender is unlikely to provide that consent so long as we have significant unpaid indebtedness outstanding.

***Ownership of our common stock is highly concentrated, and such concentration may prevent other stockholders from influencing significant corporate decisions and may result in conflicts of interest that could cause our stock price to decline.***

Our directors, officers and principal stockholders (stockholders owning 10% or more of our common stock) and their affiliates beneficially owned approximately 4,348,381 shares or 58.5% of the outstanding shares of common stock, stock options, and derivatives that could have been converted to common stock at December 31, 2014, and 53.2% of the outstanding shares of common stock, options and derivatives that could have been converted to common stock as of the filing of this Annual Report on Form 10-K. Such stockholders will have significant influence over the outcome of all matters submitted to our stockholders for approval, including the election of directors and other corporate actions.

Two of our Directors, Ryan A. Lowe and Lance Helfert, serve on the investment committee of West Coast Asset Management, Inc. West Coast Asset Management is the managing member of West Coast Opportunity Fund, LLC, a private investment vehicle formed for the purpose of investing in a wide variety of securities and financial instruments. West Coast Asset Management's principals also manage Montecito Venture Partners, LLC. West Coast Opportunity Fund and Montecito Venture Partners, LLC together beneficially owned 51% of our common stock and 15% of our Series A preferred stock at December 31, 2014. Currently they own 46.4% of our common stock and 15% of our Series A preferred stock.

In addition, we engage from time to time in transactions with certain of these significant stockholders.

As discussed more fully in Note 5 to the financial statements, on September 27, 2013, West Coast Opportunity Fund, LLC exchanged 123,539,227 Black Raven Energy, Inc. common shares for 41,327,516 common shares of our common stock.

As stated above, West Coast Opportunity Fund and Montecito Venture Partners, affiliates of our directors Mr. Lowe and Mr. Helfert, beneficially own, as of December 31, 2014, 51% of our common stock and 7.6% of our Series A preferred stock.

The interests of West Coast Opportunity Fund and Montecito Venture Partners, and their affiliates, may differ from those of our other stockholders. West Coast Opportunity Fund and Montecito Venture Partners, and their affiliates are in the business of making investments in companies and maximizing the return on those investments. They currently have, and may from time to time in the future acquire, interests in businesses that directly or indirectly compete with certain aspects of our business or our suppliers' or customers' businesses.

As of December 31, 2014, West Coast Opportunity Fund and Montecito Venture Partners were parties to an irrevocable voting and proxy agreement, by which Montecito Venture Partners granted to West Coast Opportunity Fund a proxy to vote Montecito Venture Partners shares with regard to the election of our board of directors. That irrevocable voting and proxy agreement gave West Coast Opportunity Fund the power to elect a majority of the members of our board of directors. These stockholders also may exert influence in delaying or preventing a change in control of the Company, even if such change in control would benefit the other stockholders of the Company. In addition, the significant concentration of stock ownership may affect adversely the market value of EnerJex's common stock and Series A preferred stock due to investors' perception that conflicts of interest may exist or arise. On March 23, 2015, the irrevocable voting and proxy agreement was terminated pursuant to written agreement.

***We have derivative securities currently outstanding and we may issue derivative securities in the future. Exercise of the derivatives will cause dilution to existing and new stockholders.***

The exercise of our outstanding options and warrants, will cause additional shares of common stock to be issued, resulting in dilution to our existing and future common stockholders

***We have the ability to issue additional shares of our common stock and preferred stock without asking for stockholder approval, which could cause your investment to be diluted.***

Our amended and restated articles of incorporation authorize the board of directors to issue up to 250,000,000 shares of common stock and 25,000,000 shares of preferred stock. The power of the board of directors to issue shares of common stock, preferred stock or warrants or options to purchase shares of common stock or preferred stock is generally not subject to shareholder approval. Accordingly, any additional issuance of our common stock, or preferred stock that may be convertible into common stock, or debt instruments that may be convertible into common or preferred stock, may have the effect of diluting one's investment.

***Although our common stock and Series A preferred stock are traded on the NYSE MKT, daily trading volumes are small making it difficult for investors to sell their shares.***

Our common stock and our Series A preferred stock trade on the NYSE MKT under the symbol "ENRJ," and “ENRJ.P,” respectively but trading volume has been minimal. Therefore, the market for our common stock is limited. The trading price of our stock could be subject to wide fluctuations. Investors may not be able to purchase additional shares or sell their shares within the time frame or at a price they desire.

***The price of our common stock and Series A preferred stock may be volatile and you may not be able to resell your shares at a favorable price.***

Regardless of whether an active trading market for our stock develops, the market price of our stock may be volatile and you may not be able to resell your shares at or above the price you paid for such shares. Many factors beyond our control, including but not limited to the following factors could affect our stock price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income or loss per share, net income or loss and revenues;
- changes in revenue or earnings estimates or publication of research reports by analysts about us or the exploration and production industry;
- potentially limited liquidity;
- actual or anticipated variations in our reserve estimates and quarterly operating results;
- changes in oil and gas prices;
- sales of our common stock by significant stockholders and future issuances of our common stock;
- increases in our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- commencement of or involvement in litigation;
- changes in market valuations of similar companies;
- additions or departures of key management personnel;
- general market conditions, including fluctuations in and the occurrence of events or trends affecting the price of oil and gas; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

***Our amended and restated articles of incorporation, restated bylaws and Nevada Law contain provisions that could discourage an acquisition or change of control of us.***

Our amended and restated articles of incorporation authorize our board of directors to issue preferred stock and common stock without stockholder approval. The election by our board of directors to issue Series A preferred stock, and any future election to issue more preferred stock, could make it more difficult for a third party to acquire control of us. In addition, provisions of the articles of incorporation and bylaws could also make it more difficult for a third party to acquire control of us. In addition, Nevada's "Combination with Interested Stockholders' Statute" and its "Control Share Acquisition Statute" may have the effect in the future of delaying or making it more difficult to effect a change in control of us.

These statutory anti-takeover measures may have certain negative consequences, including an effect on the ability of our stockholders or other individuals to (i) change the composition of the incumbent board of directors; (ii) benefit from certain transactions which are opposed by the incumbent board of directors; and (iii) make a tender offer or attempt to gain control of us, even if such attempt were beneficial to us and our stockholders. Since such measures may also discourage the accumulations of large blocks of our common stock by purchasers whose objective is to seek control of us or have such common stock repurchased by us or other persons at a premium, these measures could also depress the market price of our common stock. Accordingly, our stockholders may be deprived of certain opportunities to realize the "control premium" associated with take-over attempts.

***We have no plans to pay dividends on our common stock. You may not receive funds without selling your stock.***

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy with regard to our common stock is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, investment opportunities and restrictions imposed by our debentures and Credit Facility.

**Additional Risks and Uncertainties**

We are an oil and gas acquisition, exploration and development company. If any of the risks that we face actually occur, irrespective of whether those risks are described in this section or elsewhere in this report, our business, financial condition and operating results could be materially adversely affected.

## ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

## ITEM 3. LEGAL PROCEEDINGS.

None

## ITEM 4. MINE SAFETY DISCLOSURE

None

# PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

***Market Information for Common Stock***

Our common stock trades on the NYSE MKT under the symbol "ENRJ." The following table lists the quotations for the high and low sales prices of our common stock for the years ended December 31, 2013 and December 31, 2014. The market price of our common stock has been volatile. For an additional discussion, see "Item 1A: Risk Factors" of this Annual Report on Form 10-K.

| | High | Low |
|---|---|---|
| Year Ended December 31, 2013 | | |
| Quarter ended March 31, 2013 | $ 10.35 | $ 6.90 |
| Quarter ended June 30, 2013 | $ 10.35 | $ 7.35 |
| Quarter ended September 30, 2013 | $ 11.25 | $ 7.05 |
| Quarter ended December 31, 2013 | $ 9.45 | $ 7.05 |
| Year Ended December 31, 2014 | | |
| Quarter ended March 31, 2014 | $ 8.55 | $ 7.05 |
| Quarter ended June 30, 2014 | $ 9.10 | $ 6.75 |
| Quarter ended September 30, 2014 | $ 7.70 | $ 5.91 |
| Quarter ended December 31, 2014 | $ 6.22 | $ 2.00 |

***Holders***

As of March 31, 2015, there were 362 holders of record of our common stock, and 16 holders of record of our Series A preferred stock.

***Dividends***

We have never paid or declared any cash dividends on our common stock. We pay a monthly dividend of $.20833 per share or $2.50 annual dividend per share on the Company's non-convertible 10.0% Series A Cumulative Redeemable Perpetual Preferred Stock. We currently intend to retain any future earnings in excess of debt repayments and Series A preferred stock dividends to finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future. In addition, we are contractually prohibited by the terms of our outstanding debt from paying cash dividends on our common stock. Payment of future dividends on common stock, if any, will be at the discretion of our Board of Directors and will depend on our financial condition, results of operations, capital requirements, restrictions contained in current or future financing instruments, including the consent of debt holders and holders of Series A Shares, if applicable at such time, and other factors our Board of Directors deems relevant.

**Securities Authorized for Issuance under Equity Compensation Plans**

The following table sets forth information as of fiscal year ended December 31, 2014, regarding outstanding options granted under our stock option plans and options reserved for future grant under the plans.

| Plan Category | Number of shares to be issued upon exercise of outstanding options, warrants and rights (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of shares remaining available for future issuance under equity compensation plans (excluding shares reflected in column (a) (c) |
|---|---|---|---|
| Equity compensation plans approved by stockholders | 231,332 | $ 9.33 | 484,156 |

**Recent Sales of Unregistered Securities**

None.

**Issuer Purchases of Equity Securities**

None.

**ITEM 6. SELECTED FINANCIAL DATA.**

Not applicable.

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

This Management's Discussion and Analysis of Financial Condition and Results of Operations section should read in conjunction with the other sections of this Annual Report on Form 10-K, including "Items 1 and 2. Business and Properties" and "Item 8: Financial Statements and Supplementary Data". This section includes forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act. Forward-looking statements such as "will", "believe," "are projected to be" and similar expressions are statements regarding future events or our future performance, and include statements regarding projected operating results. These forward-looking statements are based on current expectations, beliefs, intentions, strategies, forecasts and assumptions and involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by these forward-looking statements. These risks include, but are not limited to: our ability to deploy capital in a manner that maximizes stockholder value; the ability to identify suitable acquisition candidates or business and investments opportunities; the ability to reduce our operating costs; general economic conditions and our expected liquidity in future periods. These forward-looking statements are based on our current expectations and could be affected by the uncertainties and risk factors described throughout this filing and particularly in the "Risk Factors" set forth in Part I, Item 1A of this Annual Report on Form 10-K. As a result, our actual results may differ materially from those anticipated in these forward-looking statements.

**Overview**

Our principal strategy is to develop, acquire, explore and produce domestic onshore oil and gas properties. Our business activities are currently focused in Kansas, Colorado, Nebraska, and Texas.

**Results of Operations**

The following table presents selected information regarding our operating results from continuing operations. For the year ended December 31, 2013, only the results of operations for the fourth quarter for Black Raven are included due to the merger with Black Raven Energy, Inc. on September 27, 2013 (see Note 5).

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 | Difference |
|---|---|---|---|
| Oil & gas revenues [1] | | | |

| | | | |
|---|---|---|---|
| Crude oil revenues | $ 13,257,608 | $ 10,824,575 | $ 2,433,033 |
| Average price per Bbl | 84.40 | 94.86 | (10.46) |
| Natural gas revenues | 1,035,759 | 117,695 | 918,064 |
| Average price per Mcf | 3.18 | 3.01 | 0.17 |
| Expenses: | | | |
| Lease operating expenses (2) | 6,762,248 | 4,095,850 | 2,666,398 |
| Depreciation, depletion and amortization (3) | 3,259,442 | 1,691,008 | 1,568,434 |
| Total production expenses | 10,021,690 | 5,786,858 | 4,234,832 |
| Professional fees (4) | 987,229 | 1,071,740 | (84,511) |
| Salaries | 1,479,688 | 1,432,081 | 47,607 |
| Depreciation - other fixed assets | 289,803 | 165,652 | 124,151 |
| Administrative expenses | 790,572 | 798,457 | (7,885) |
| Total expenses | $ 13,568,982 | $ 9,254,788 | $ 4,314,194 |

(1) 2014 crude oil revenues increased $2.4 million or 22% to 13.3 million from $10.8 million in fiscal 2013. The crude oil revenue increase was due primarily to increased sales. Sales increased by approximately 43,000 bbls or 38% to 157,089 bbls in 2014 compared to sales of 114,112 in 2013. This increase was due primarily to new production from our Colorado assets that resulted from our acquisition of Black Raven Energy, Inc. on September 27, 2013, as more fully described in Note 5. Revenue increases due to increased sales volumes was partially offset by decreases to our realized prices. Realized prices dropped $10.46 during 2014 from $94.86 per bbl in 2013 to $84.40 per bbl in 2014. 2014 natural gas revenues increased $0.9 million to $1.0 million from $0.1 million in 2013. This increase was due to increased sales of natural gas. Sales of natural gas increased by approximately 290,000 mcf in 2014 from 39,135 mcf in 2013 to 325,894 mcf in 2014. Again, this increase was due new production from our Colorado assets that resulted from our acquisition of Black Raven Energy, Inc. on September 27, 2013 (see note 5 to our financial statements).

(2) 2014 lease operating expenses increased $2.7 million or 65% to $6.8 million from $4.1 million in 2013. However, lease operating expenses per boe decreased $1.96 per boe or 5.8% to $31.99 in 2014 from $33.95 per boe in 2013. The 65% increase in lease operating expenses in 2014 was due primarily to increased operating expenses associated with the new Colorado production that resulted from our acquisition of Black Raven Energy, Inc. on September 27, 2013 (see note 5 to financial statements).

(3) 2014 depletion expense increased approximately 93% to approximately $3.3 million compared to $1.7 million for 2013. The depletion expense increase is due primarily to increased production levels as note in (2) above. Depletion expense per boe increased $1.40 or 10% in 2014 compared to 2013.

(4) 2014 professional fees were $1.0 million, compared to $1.1 million during 2013. Professional fees decreased as a result of reduced legal fees partially offset by increased consulting and investor relation fees.

**Reserves**

| Proved Reserves | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Total proved PV10 (present value) of reserves | $ 64,318,700 | $ 102,411,800 |
| Total proved reserves (BOE) | $ 4,400,180 | $ 5,804,600 |
| Average Price (per bbl) | $ 85.27 | $ 87.89 |
| Average Price (per mcf) | $ 3.52 | $ 2.85 |

Of the 4.4 million BOE of total proved reserves, approximately 50% are classified as proved developed producing, approximately 19% are classified as proved developed non-producing, and approximately 31% are classified as proved undeveloped.

The following table presents summary information regarding our estimated net proved reserves as of December 31, 2014. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. The estimates of net proved reserves are based on the reserve reports prepared by MHA Petroleum Consultants LLC, our independent petroleum consultants. For additional information regarding our reserves, please see Note 15 to our audited financial statements as of and for the fiscal year ended December 31, 2014.

**Summary of Proved Oil and Gas Reserves**
**as of December 31, 2014**

| Proved Reserves Category | Gross BOE | Net BOE | PV10 (before tax) (1) |
|---|---|---|---|
| Proved, Developed | 4,579,675 | 3,048,261 | $ 51,942,267 |
| Proved, Undeveloped | 1,754,621 | 1,351,919 | $ 12,376,515 |
| Total Proved Reserves | 6,334,296 | 4,400,180 | $ 64,318,782 |

(1) The following table shows our reconciliation of our PV10 to our standardized measure of discounted future net cash flows (the most direct comparable measure calculated and presented in accordance with GAAP). PV10 is our estimate of the present value of future net revenues from estimated proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." We believe PV10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV10 on the same basis. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

| | As of December 31, 2014 | As of December 31, 2013 |
|---|---|---|
| PV10 (before tax) | $ 64,318,782 | $ 102,411,800 |
| Future income taxes, net of 10% discount | $ (1,614,931) | $ (20,964,145) |
| Standardized measure of discounted future net cash flows | $ 62,703,851 | $ 81,447,655 |

**Liquidity and Capital Resources**

Liquidity is a measure of a company's ability to meet potential cash requirements. We have historically met our capital requirements through debt financing, revenues from operations and the issuance of equity securities. We believe that our historical means of meeting our capital requirements will provide us with adequate liquidity to fund our operations.

The following table summarizes total current assets, total current liabilities and working capital at year ended December 31, 2014 compared to the year ended December 31, 2013.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 | Difference |
|---|---|---|---|
| Current Assets | $ 7,411,168 | $ 5,401,304 | $ 2,009,864 |
| Current Liabilities | $ 4,139,356 | $ 6,506,178 | $ (2,366,822) |
| Working Capital (deficit) | $ 3,271,812 | $ (1,104,874) | $ 4,376,686 |

**Senior Secured Credit Facility**

On October 3, 2011, the Company, DD Energy, Inc., EnerJex Kansas, Inc., Black Sable Energy, LLC and Working Interest, LLC ("Borrowers") entered into an Amended and Restated Credit Agreement with Texas Capital Bank, N.A. ("Bank") and other financial institutions and banks that may become a party to the Credit Agreement from time to time. The facilities provided under the Amended and Restated Credit Agreement were to be used to refinance Borrowers prior outstanding revolving loan facility with Bank, dated July 3, 2008, and for working capital and general corporate purposes.

At our option, loans under the facility will bear stated interest based on the Base Rate plus Base Rate Margin, or Floating Rate plus Floating Rate Margin (as those terms are defined in the Credit Agreement). The Base Rate will be, for any day, a fluctuating rate per annum equal to the higher of (a) the Federal Funds Rate plus 0.50% and (b) the Bank's prime rate. The Floating Rate shall mean, at Borrower's option, a per annum interest rate equal to (i) the Eurodollar Rate plus Eurodollar Margin, or (ii) the Base Rate plus Base Rate Margin (as those terms are defined in the Amended and Restated Credit Agreement). Eurodollar borrowings may be for one, two, three, or six months, as selected by the Borrowers. The margins for all loans are based on a pricing grid ranging from 0.00% to 0.75% for the Base Rate Margin and 2.25% to 3.00% for the Floating Rate Margin based on the Company's Borrowing Base Utilization Percentage (as defined in the Amended and Restated Credit Agreement).

On December 15, 2011, we entered into a First Amendment to Amended and Restated Credit Agreement and Second Amended and Restated Promissory Note in the amount of $50,000,000 with the Bank. The Amendment reflects the addition of Rantoul Partners, as an additional Borrower and adds as additional security for the loans the assets held by Rantoul Partners.

On August 31, 2012, we entered into a Second Amendment to Amended and Restated Credit Agreement with the Bank. The Second Amendment: (i) increased the borrowing base to $7,000,000 (ii) reduced the minimum interest rate to 3.75% and (iii) added additional new leases as collateral for the loan.

On November 2, 2012, we entered into a Third Amendment to Amended and Restated Credit Agreement with the Bank. The Third Amendment (i) increased the borrowing base to $12,150,000 and (ii) clarified certain continuing covenants and provided a limited waiver of compliance with one of the covenants so clarified for the fiscal quarter ended December 31, 2011.

On January 24, 2013, we entered into a Fourth Amendment to Amended and Restated Credit Agreement, which was made effective as of December 31, 2012 with the Bank. The Fourth Amendment reflects the following changes: (i) the Bank consented to the restructuring transactions related to the dissolution of Rantoul Partners, and (ii) the Bank terminated a Limited Guaranty, as defined in the Credit Agreement, executed by Rantoul Partners in favor of the Bank

On April 16, 2013, the Bank increased our borrowing base to $19.5 million.

On September 30, 2013, we entered into a Fifth Amendment to the Amended and Restated Credit Agreement. The Fifth Amendment reflects the following changes: (i) expanded principal commitment amount of the Bank to $100,000,000; (ii) increased the Borrowing Base to $38,000,000; (iii) added Black Raven Energy, Inc. to the Credit Agreement as borrower parties; (iv) added certain collateral and security interests in favor of the Bank; and (v) reduced the Company's current interest rate to 3.30%.

On November 19, 2013, we entered into a Sixth Amendment to the Amended and Restated Credit Agreement. The Sixth Amendment reflects the following changes: (i) the addition of Iberia Bank as a participant in our credit facility, and (ii) a technical correction to our covenant calculations.

On May 22, 2014, we entered into a Seventh Amendment to the Amended and Restated Credit Agreement. The Seventh Amendment reflects the Bank's consent to our issuance of up to 850,000 shares of our 10% Series A Cumulative Redeemable Perpetual Preferred Stock.

On August 15, 2014, we entered into an Eighth Amendment to the Amended and Restated Credit Agreement. The Eighth Amendment reflects the following changes: (i) the borrowing base was increased from $38 million to $40 million, and (ii) the maturity of the facility was extended by three years to October 3, 2018.

**Summary of product research and development that we will perform for the term of our plan**

We do not anticipate performing any significant product research and development under our plan of operation.

**Expected purchase or sale of any significant equipment**

We anticipate that we will purchase the necessary production and field service equipment required to produce oil and gas during our normal course of operations over the next 12 months.

**Significant changes in the number of employees**

We currently have 29 full-time employees including field personnel. As production and drilling activities increase or decrease, we will adjust our technical, operational and administrative personnel as appropriate. We use and will continue to use independent consultants and contractors to perform various professional services, particularly in the area of land services, reservoir engineering, geology, drilling, water hauling, pipeline construction, well design, well-site monitoring and surveillance, permitting and environmental assessment. We believe that this use of third-party service providers may enhance our ability to contain operating and general expenses, and capital costs.

**Off-Balance Sheet Arrangements**

We do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

**Critical Accounting Policies and Estimates**

Our accounting policies and estimates that are critical to our business operations and understanding of our results of operations include those relating to our oil and gas properties, asset retirement obligations and the value of share-based payments. This is not a comprehensive list of all of the accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by U.S. GAAP, with no need for our judgment in the application. There are also areas in which our judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and we may use significant judgment in the application; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see Note 1, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report.

**Oil and Gas Properties**

We follow the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities.

Proved properties are amortized using the units of production method (UOP). Currently we only have operations in the Unites States of America. The UOP calculation multiplies the percentage of estimated proved reserves produced each quarter by the cost of these reserves. The amortization base in the UOP calculation includes the sum of proved property, net of accumulated depreciation, depletion and amortization (DD&A), estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs, less related salvage value.

The cost of unproved properties are excluded from the amortization calculation until it is determined whether or not proved reserves can be assigned to such properties or until development projects are placed into service. Geological and geophysical costs not associated with specific properties are recorded as proved property immediately. Unproved properties are reviewed for impairment quarterly.

Under the full cost method of accounting, the net book value of oil and gas properties, less deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is (a) the present value of future net revenues computed by applying current prices of oil & gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil & gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of 10 percent and assuming continuation of existing economic conditions *plus* (b) the cost of properties not being amortized *plus* (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized *less* (d) income tax effects related to differences between book and tax basis of properties. Future cash outflows associated with settling accrued retirement obligations are excluded from the calculation. Estimated future cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months held flat for the life of the production, except where prices are defined by contractual arrangements.

Any excess of the net book value of proved oil and gas properties, less related deferred income taxes, over the ceiling is charged to expense and reflected as additional DD&A in the statement of operations. The ceiling calculation is performed quarterly. During the years ended December 31, 2013 and 2012 there were no impairments resulting from the quarterly ceiling tests.

Proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion (greater than 25%) of our reserve quantities are sold, in which case a gain or loss is recognized in income.

**Asset Retirement Obligations**

The asset retirement obligation relates to the plug and abandonment costs when our wells are no longer useful. We determine the value of the liability by obtaining quotes for this service and estimate the increase we will face in the future. We then discount the future value based on an intrinsic interest rate that is appropriate for us. If costs rise more than what we have expected there could be additional charges in the future however we monitor the costs of the abandoned wells and we will adjust this liability if necessary.

**Share-Based Payments**

The value we assign to the options and warrants that we issue is based on the fair market value as calculated by the Black-Scholes pricing model. To perform a calculation of the value of our options and warrants, we determine an estimate of the volatility of our stock. We need to estimate volatility because there has not been enough trading of our stock to determine an appropriate measure of volatility. We believe our estimate of volatility is reasonable, and we review the assumptions used to determine this whenever we issue a new equity instruments. If we have a material error in our estimate of the volatility of our stock, our expenses could be understated or overstated.

**Recent Issued Accounting Standards**

See Note 1, Summary of Significant Accounting Policies - Recent Issued Accounting Standards, to our consolidated financial statements included in this report.

**Effects of Inflation and Pricing**

The oil and gas industry is very cyclical and the demand for goods and services of oil and gas field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Material changes in prices impact revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate business costs and the demand for services related to production and exploration will fluctuate while the commodity price for oil and gas remains volatile.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.**

Not applicable.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

### Management Responsibility for Financial Information

We are responsible for the preparation, integrity and fair presentation of our financial statements and the other information that appears in this Annual Report on Form 10-K. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States and include estimates based on our best judgment.

We maintain a comprehensive system of internal controls and procedures designed to provide reasonable assurance, at an appropriate cost-benefit relationship, that our financial information is accurate and reliable, our assets are safeguarded and our transactions are executed in accordance with established procedures.

RBSM LLP, an independent registered public accounting firm, is retained to audit our consolidated financial statements. Its accompanying report is based on audits conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

Our consolidated financial statements and notes thereto, and other information required by this Item 8 are included in this report beginning on page F-1.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

## ITEM 9A. CONTROLS AND PROCEDURES.

### Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer, Robert G. Watson, Jr., and our Chief Financial Officer, Douglas M. Wright, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) as of the end of the period covered by this Report pursuant to Exchange Act Rule 13a-15(b). Based on the evaluation, Mr. Watson and Mr. Wright concluded that our disclosure controls and procedures are effective.

### Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as is defined in the Securities Exchange Act of 1934. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance, with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2013.

### Changes in Internal Control over Financial Reporting

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

## ITEM 9B. OTHER INFORMATION.

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2015 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2014.

## ITEM 11. EXECUTIVE COMPENSATION.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2015 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2014.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Information in response to this item is incorporated by reference from the registrant’s definitive proxy statement for its 2015 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2014.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2015 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2014.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2015 Annual Meeting of Shareholders to be filed within 120 days after December 31, 2014.

## PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following information required under this item is filed as part of this report:

### 1. Financial Statements



### 2. Financial Statement Schedules

None.

### 3. Exhibit Index

| Exhibit No. | Description |
|---|---|
| 2.1 | Agreement and Plan of Merger between Millennium Plastics Corporation and Midwest Energy, Inc. filed on August 16, 2006. |
| 2.2 | Agreement and Plan of Merger by and among Registrant, BRE Merger Sub, Inc., Black Raven Energy, Inc. and West Coast Opportunity Fund, LLC dated July 23, 2013 (incorporated herein by reference to Exhibit 10.4 on Form 8-K filed July 29, 2013). |
| 3.1 | Amended and Restated Articles of Incorporation, as currently in effect (incorporated by reference to Exhibit 3.1 to the Form 10-Q filed on August 14, 2008) |

| | |
|---|---|
| 3.2 | Amended and Restated Bylaws, as currently in effect (incorporated by reference to Appendix C to Schedule 14A filed on June 6, 2013) |
| 3.3 | Certificate of Amendment of Articles of Incorporation as filed with the Nevada Secretary of State on May 29, 2014 (incorporated herein by reference as Exhibit 3.1 on Current Report Form 8-K filed on May 29, 2014) |
| 3.4 | Certificate of Amendment of Articles of Incorporation (incorporated by reference as Exhibit 3.1 on Current Report Form 8-K filed on May 29, 2014) |
| 3.5 | Amended and Restated Certificate of Designation for Series A Preferred Stock (incorporated by reference to Exhibit 4.6 to the Form S-1/A filed on June 3, 2014) |
| 3.6 | Certificate of Designation of Preferences, Rights and Limitations of Series B Convertible Preferred Stock (incorporated herein by reference as Exhibit 4.1 on Current Report Form 8-K filed on March 11, 2015) |
| 4.1 | Specimen common stock certificate (incorporated by reference to Exhibit 4.3 to the Form S-1/A filed on May 27, 2008) |
| 4.2 | Specimen Series A Preferred Stock Certificate (incorporated by reference to Exhibit 4.4 to the Form S-1/A filed on June 3, 2014) |
| 4.3 | Specimen Series B Convertible Preferred Stock Certificate (incorporated herein by reference as Exhibit 4.2 on Current Report Form 8-K filed on March 11, 2015) |
| 4.4 | Certificate of Designation for Series A Preferred Stock (incorporated by reference to Exhibit 4.1 to the Form 8-K filed on January 6, 2011). |
| 4.5 | Form of Warrant to Purchase Common Stock (incorporated herein by reference as Exhibit 4.3 on Current Report Form 8-K filed on March 11, 2015) |
| 4.6 | Form of Placement Agent Warrant (incorporated herein by reference as Exhibit 4.4 on Current Report Form 8-K filed on March 11, 2015) |
| 10.1 | Form of Officer and Director Indemnification Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on October 16, 2008) |
| 10.2 | Amendment 4 to Joint Exploration Agreement effective as of November 6, 2008 between MorMeg, LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.15 to the Form 10-K filed July 14, 2009) |
| 10.3 | Amendment 5 to Joint Exploration Agreement effective as of December 31, 2009 between MorMeg LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.15 to the Form 10-Q filed on February 16, 2010) |
| 10.4 | Amendment 6 to Joint Exploration Agreement effective as of March 31, 2010 between MorMeg LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.24 to the Form 10-K filed on July 15, 2010) |
| 10.5 | Amended and Restated EnerJex Resources, Inc. Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on October 16, 2008) |
| 10.6 | Joint Development Agreement between EnerJex Resources, Inc. and Haas Petroleum, LLC dated December 31, 2010 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on January 27, 2011). |
| 10.7 | Joint Operating Agreement between EnerJex Resources, Inc. and Haas Petroleum, LLC and MorMeg, LLC dated December 31, 2010 (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on January 27, 2011). |
| 10.8 | Amended and Restated Credit Agreement dated October 3, 2011 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on October 6, 2011). |
| 10.9 | Option and Joint Development Agreement by and among Registrant and MorMeg, LLC dated August 2011 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on November 15, 2011). |
| 10.10 | First Amendment to Amended and Restated Credit Agreement dated December 14, 2011 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on December 14, 2011). |
| 10.11 | Second Amendment to Amended and Restated Credit Agreement dated August 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on November 8, 2012). |
| 10.12 | Third Amendment to Amended and Restated Credit Agreement dated November 2, 2012 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on November 8, 2012). |
| 10.13 | Amended and Restated Employment Agreement by and among Registrant and Robert G. Watson, Jr. dated December 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on January 4, 2013). |
| 10.14 | Fourth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on January 30, 2013). |
| 10.15 | First Amendment to Amended & Restated Mortgage Security Agreement, Financing Statement and Assignment of Production by and among Working Interest, LLC and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.3 on Form 8-K filed on January 30, 2013). |
| 10.16 | Mortgage, Security Agreement, Financing Statement and Assignment of Production and Revenues by and among Working Interest, LLC and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.4 on Form 8-K filed on January 30, 2013). |
| 10.17 | 2013 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 on Registration Statement on Form S-8 filed on June 12, 2013) |
| 10.18 | Fifth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated September 30, 2013 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed October 1, 2013). |
| 10.19 | Sixth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated November 19, 2013 (incorporated by reference to Exhibit 10.37 on Form 10-Q filed May 13, 2014). |
| 10.20 | Exchange Agreement between EnerJex Resources, Inc. and holders of Series A preferred stock (incorporated by reference to Exhibit 10.38 on Form S-1/A Amendment No. 2 filed June 3, 2014). |
| 10.21 | Seventh Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated May 22, 2014 (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 27, 2014). |
| 10.22 | Form of Securities Purchase Agreement dated as of March 11, 2015 (incorporated herein by reference as Exhibit 10.1 on Current Report Form 8-K filed on March 11, 2015) |

| | |
|---|---|
| 10.23 | Eighth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated August 13, 2014.* |

| | |
|---|---|
| 21.1 | Subsidiaries* |
| 23.2 | Consent of MHA Petroleum Consultants, LLC* |
| 24.1 | Power of Attorney (included with signatures).* |
| 31.1 | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002* |
| 31.2 | Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002* |
| 32.1 | Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002* |
| 32.2 | Certificate of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002* |
| | |
| 101.INS | XBRL Instance Document* |
| 101.SCH | XBRL Taxonomy Extension Schema Document* |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document* |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document* |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document* |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document* |

* Filed herewith.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this amended report to be signed on its behalf by the undersigned, thereunto duly authorized.

**ENERJEX RESOURCES, INC.**

By: /s/ Robert G. Watson, Jr.
Robert G. Watson, Jr., Chief Executive Officer

Date: March 31, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

| Name | Title | Date |
|---|---|---|
| /s/ Robert G. Watson, Jr.<br>Robert G. Watson, Jr. | President, Chief Executive Officer,<br>(Principal Executive Officer), Secretary and Director | March 31, 2015 |
| /s/ Douglas M. Wright<br>Douglas M. Wright | Chief Financial Officer (Principal Financial Officer) | March 31, 2015 |
| /s/ Ryan A. Lowe<br>Ryan A. Lowe | Director and Senior Vice President of Corporate Marketing | March 31, 2015 |
| /s/ Lance W. Helfert<br>Lance Helfert | Director | March 31, 2015 |
| /s/ James G. Miller<br>James G. Miller | Director | March 31, 2015 |
| /s/ Richard E. Menchaca<br>Richard E. Menchaca | Director | March 31, 2015 |

**Index to Financial Statements**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

EnerJex Resources, Inc.

We have audited the accompanying consolidated balance sheet of EnerJex Resources, Inc. and Subsidiaries as of December 31, 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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 audit 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 audit provides 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 EnerJex Resources, Inc. and Subsidiaries as of December 31, 2013, and the results of its consolidated operations, stockholders' equity, and cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

L.L. Bradford & Company, LLC

Leawood, Kansas

March 28, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

EnerJex Resources, Inc.

We have audited the accompanying consolidated balance sheet of EnerJex Resources, Inc. and Subsidiaries as of December 31, 2014, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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 audit 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 audit provides 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 EnerJex Resources, Inc. and Subsidiaries as of December 31, 2014, and the results of its consolidated operations, stockholders' equity, and cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

RBSM, LLP

Leawood, Kansas

March 31, 2015

**EnerJex Resources, Inc. and Subsidiaries**
**Consolidated Balance Sheets**

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| Assets | | |
| Current Assets: | | |
| Cash | $ 805,524 | $ 1,079,356 |
| Restricted Cash | - | 228,840 |
| Accounts receivable | 1,278,509 | 2,461,746 |
| Derivative receivable | 3,736,005 | - |
| Inventory | 248,218 | 238,794 |
| Marketable securities | 1,018,573 | 1,018,573 |
| Deposits and prepaid expenses | 324,339 | 373,994 |
| Total current assets | 7,411,168 | 5,401,303 |
| | | |
| Non-current assets: | | |
| Fixed assets, net of accumulated depreciation of $1,945,607 and $1,785,401 | 2,404,703 | 2,406,591 |
| Oil & gas properties using full cost accounting, net of accumulated DD&A of $13,827,347 and $10,567,906 | 64,263,272 | 61,349,403 |
| Derivative receivable | 985,746 | - |
| Other non-current assets | 993,207 | 834,180 |
| Total non-current assets | 68,646,928 | 64,590,174 |
| Total assets | $ 76,058,096 | $ 69,991,477 |
| | | |
| Liabilities and Stockholders' Equity | | |
| | | |
| Current liabilities: | | |
| Accounts payable | $ 3,042,835 | $ 2,424,009 |
| Accrued liabilities | 1,096,521 | 3,070,461 |
| Derivative liability | - | 1,011,708 |
| Total current liabilities | 4,139,356 | 6,506,178 |
| | | |
| Non-Current Liabilities: | | |
| Asset retirement obligation | 2,906,093 | 2,687,801 |
| Derivative liability | - | 339,642 |
| Long-term debt | 23,011,660 | 31,547,255 |
| Total non-current liabilities | 25,917,753 | 34,574,698 |
| Total liabilities | 30,057,109 | 41,080,876 |
| | | |
| Commitments and Contingencies | | |
| | | |
| Stockholders' Equity: | | |
| 10% Series A Cumulative Redeemable Perpetual Preferred Stock, $.001 par value, 25,000,000 shares authorized; 751,815 shares issued and outstanding at December 31, 2014 | 752 | - |
| Preferred stock, $0.001 par value, 25,000,000 shares authorized, 4,779,460 shares issued and outstanding at December 31, 2013 | - | 4,780 |
| Common stock, $0.001 par value, 250,000,000 shares authorized; shares issued and outstanding – 7,643,114 at December 31, 2014 and 7,307,158 at December 31, 2013 | 7,643 | 7,307 |
| Accumulated other comprehensive income | (552,589) | (552,589) |
| Paid in capital | 63,825,998 | 49,913,509 |
| Retained (deficit) | (17,280,817) | (20,462,406) |
| Total stockholders' equity | 46,000,987 | 28,910,601 |
| Total liabilities and stockholders' equity | $ 76,058,096 | $ 69,991,477 |

**See Notes to Consolidated Financial Statements.**

**EnerJex Resources, Inc. and Subsidiaries**
**Consolidated Statements of Operations**

| | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| Crude oil revenues | $ 13,257,608 | $ 10,824,575 |
| Natural gas revenues | 1,035,759 | 117,695 |
| Total revenues | 14,293,367 | 10,942,270 |
| | | |
| Expenses: | | |
| Direct operating costs | 6,762,248 | 4,095,850 |
| Depreciation, depletion and amortization | 3,549,245 | 1,856,660 |
| Professional fees | 987,229 | 1,071,740 |
| Salaries | 1,479,688 | 1,432,081 |
| Administrative expense | 790,572 | 798,457 |
| Total expenses | 13,568,982 | 9,254,788 |
| Income from operations | 724,385 | 1,687,482 |
| | | |
| Other income (expense): | | |
| Interest expense | (1,305,194) | (772,471) |
| Gain (loss) on derivatives | 4,993,262 | (740,456) |
| Other income | 161,171 | 1,115,898 |
| Total other income (expense) | 3,849,239 | (397,029) |
| Income before provision for income taxes | 4,573,624 | 1,290,453 |
| Provision for income taxes | - | - |
| | | |
| Net income | $ 4,573,624 | $ 1,290,453 |
| | | |
| Net income | $ 4,573,624 | $ 1,290,453 |
| Preferred dividends | (1,392,035) | (1,039,516) |
| Net income (loss) attributable to common stockholders | $ 3,181,589 | $ 250,937 |
| Net income (loss) per common share basic and diluted | 0.42 | 0.04 |
| Weighted Average Shares | $ 7,492,007 | $ 5,596,062 |

**See Notes to Consolidated Financial Statements.**

**EnerJex Resources, Inc. and Subsidiaries**
**Consolidated Statement of Stockholders' Equity**

| | 10% Series A Preferred Stock | | Preferred Stock | | Common Stock | | Accumulated Other Comprehensive | | | Total Stockholders' |
|---|---|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount | Income | Paid In Capital | Retained Deficit | Equity |
| Balance, January 1, 2013 | | $ | 4,779,460 | $ 4,780 | 4,545,990 | $ 4,546 | $ (552,589) | $ 42,870,137 | $ (20,713,343) | $ 21,613,531 |
| Stock issued for services | | | | | 6,000 | 6 | | 44,994 | | 45,000 |
| Issuance of stock options | | | | | | | | 72,434 | | 72,434 |
| Warrants issued for services | | | | | | | | 40,790 | | 40,790 |
| Stock issued for shares of Black Raven Energy, Inc. | | | | | 2,755,168 | 2,755 | | 6,885,154 | | 6,887,909 |
| Dividends paid on preferred stock | | | | | | | | | (1,039,516) | (1,039,516) |
| Net income for the year | | | | | | | | | 1,290,453 | 1,290,453 |
| Balance, December 31, 2013 | | | 4,779,460 | 4,780 | 7,307,158 | 7,307 | (552,589) | 49,913,509 | (20,462,406) | 28,910,601 |
| Stock Issued for Services | | | | | 17,332 | 17 | | 234,637 | | 234,654 |
| Issuance of Stock Options | | | | | | | | 326,579 | | 326,579 |
| Issuance of 10% series A Cumulative Redeemable Perpetual Preferred Stock and retirement of legacy preferred stock | 751,815 | 752 | (4,779,460) | (4,780) | 318,624 | 319 | | 13,351,273 | | 13,347,564 |
| Dividends Paid on Preferred Stock | | | | | | | | | (1,392,035) | (1,392,035) |
| Net Income for the Year | | | | | | | | | 4,573,624 | 4,573,624 |
| Balance, December 31, 2014 | 751,815 | $ 752 | 0 | $ 0 | 7,643,114 | $ 7,643 | $ (552,589) | $ 63,825,998 | $ (17,280,817) | $ 46,000,987 |

**See Notes to Consolidated Financial Statements.**

**EnerJex Resources, Inc. and Subsidiaries**
**Consolidated Statements of Cash Flows**

| | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net Income | $ 4,573,624 | $ 1,290,453 |
| Depreciation, depletion and amortization | 3,549,245 | 1,856,660 |
| Stock, options and warrants issued for services | 638,171 | 255,977 |
| Accretion of asset retirement obligation | 255,836 | 139,779 |
| Settlement of asset retirement obligations | (102,930) | (36,758) |
| (Gain) on derivatives | (6,073,101) | (448,945) |
| Loss on sale of fixed assets | 9,738 | 5,833 |
| Adjustments to reconcile net income to cash from operating activities: | | |
| Accounts receivable | 1,183,237 | (361,314) |
| Inventory | (9,424) | 34,336 |
| Deposits and prepaid expenses | (27,282) | 235,471 |
| Accounts payable | 618,826 | (545,112) |
| Accrued liabilities | (1,973,941) | 686,441 |
| Cash flows from operating activities | 2,641,999 | 3,112,821 |
| | | |
| **Cash flows from investing activities** | | |
| Purchase of fixed assets | (298,903) | (184,794) |
| Additions to oil and gas properties | (7,095,865) | (7,672,492) |
| Sale of oil and gas properties | 987,939 | 454,975 |
| Settlements of asset retirement obligations | - | (18,910) |
| Proceeds from sale of fixed assets | 1,250 | 12,755 |
| Net cash acquired from Black Raven | - | 656,693 |
| Cash flows from investing activities | (6,405,579) | (6,751,773) |
| | | |
| **Cash flows from financing activities** | | |
| Proceeds from sale of preferred stock | 13,347,564 | - |
| Repayments of long-term debt | (14,035,595) | (9,096) |
| Borrowings on long-term debt | 5,500,000 | 6,000,000 |
| Dividends paid on preferred stock | (1,392,035) | (757,992) |
| Repayments of notes payable | - | (825,000) |
| Deferred financing costs | (159,026) | (228,258) |
| Cash flows from financing activities | 3,260,908 | 4,179,654 |
| Increase (decrease) in cash and cash equivalents | (502,672) | 540,702 |
| Cash and cash equivalents, beginning | 1,308,196 | 767,494 |
| Cash and cash equivalents, end | $ 805,524 | $ 1,308,196 |
| | | |
| Supplemental disclosures: | | |
| Interest paid | $ 741,757 | $ 375,932 |
| Income taxes paid | $ - | $ - |
| Non-cash transactions: | | |
| Share-based payments issued for services | $ 638,171 | $ 216,810 |
| Preferred dividends payable | $ - | $ 456,289 |

**See Notes to Consolidated Financial Statements.**

**EnerJex Resources, Inc.**
**Notes to Consolidated Financial Statements**

## Note 1 - Summary of Accounting Policies

### Basis of Presentation

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States. Our operations are considered to fall within a single industry segment, which are the acquisition, development, exploitation and production of crude oil and natural gas properties in the United States. Our consolidated financial statements include our wholly owned subsidiaries.

All significant intercompany balances and transactions have been eliminated upon consolidation. Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation.

As discussed further in Note 5, on September 27, 2013, we merged with Black Raven Energy, Inc. ("Black Raven"). The balance sheet accounts of Black Raven, our wholly owned subsidiary, have been consolidated as of September 30, 2013. We did not use the purchase method of accounting due to a common shareholder. Historical costs were used to combine the two entities, accordingly assets and liabilities of Black Raven were not recorded at fair value. The results of operations of Black Raven for the fourth quarter of 2013 are included in the consolidated statement of operations for the year ended December 31, 2013.

### Nature of Business

We are an independent energy company engaged in the business of producing and selling crude oil and natural gas. The crude oil and natural gas is obtained primarily by the acquisition and subsequent exploration and development of mineral leases. Development and exploration may include drilling new exploratory or development wells on these leases. These operations are conducted primarily in Kansas, Colorado, Nebraska and Texas.

### Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates included in the consolidated financial statements are: (1) oil and gas revenues and reserves; (2) depreciation, depletion and amortization; (3) valuation allowances associated with income taxes (4) accrued assets and liabilities; (5) stock-based compensation; (6) asset retirement obligations and (7) valuation of derivative instruments. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates. Actual results could differ from those estimates.

### Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear any interest. We regularly review receivables to insure that the amounts will be collected and establish or adjust an allowance for uncollectible amounts as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote.

### Share-Based Payments

The value we assign to the options and warrants that we issue is based on the fair market value as calculated by the Black-Scholes pricing model. To perform a calculation of the value of our options and warrants, we determine an estimate of the volatility of our stock. We need to estimate volatility because there has not been enough trading of our stock to determine an appropriate measure of volatility. We believe our estimate of volatility is reasonable, and we review the assumptions used to determine this whenever we issue new equity instruments.

**Income Taxes**

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted.

We routinely assess the reliability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. In addition we routinely assess uncertain tax positions, and accrue for tax positions that are not more-likely-than-not to be sustained upon examination by taxing authorities.

**Uncertain Tax Positions**

We follow guidance in Topic 740 of the Codification for its accounting for uncertain tax positions. Topic 740 prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, we determine whether it is more-likely-than-not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based solely on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

We have no liability for unrecognized tax benefits recorded as of December 31, 2014 and 2013. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the statement of operations or statement of financial position as of December 31, 2014. In addition, we do not believe that there are any positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease within the next twelve months. We recognize related interest and penalties as a component of income tax expense.

Tax years open for audit by federal tax authorities as of December 31, 2014 are the years ended December 31, 2011, 2012, 2013 and 2014. Tax years ending prior to 2011 are open for audit to the extent that net operating losses generated in those years are being carried forward or utilized in an open year.

**Fair Value Measurements**

Accounting guidance establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. We incorporate a credit risk assumption into the measurement of certain assets and liabilities.

**Cash and Cash Equivalents**

We consider all highly liquid investment instruments purchased with original maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows and other statements. We maintain cash on deposit, which, at times, exceeds federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

**Revenue Recognition**

Oil and gas revenues are recognized net of royalties when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collection of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

**Fixed Assets**

Property and equipment are recorded at cost. At December 31, 2014, Fixed Assets consisted of vehicles $967,483, furniture and equipment of $608,061, building and leasehold improvements of $23,069 and gathering and compression systems of $2,751,697, as well as accumulated depreciation of vehicles of $697,042, accumulated depreciation of furniture and fixtures of $494,333, accumulated depreciation of building and leasehold improvements of $9,386 and accumulated depreciation of gathering and compression systems of $744,846. At December 31, 2013, Fixed Assets consisted of vehicles of $900,952, furniture and equipment of $672,105, building and leasehold improvements of $19,095 and gathering and compression systems of $2,599,841 as well as accumulated depreciation of vehicles $693,093, accumulated depreciation of furniture and fixtures of $118,642, accumulated depreciation of building and leasehold improvements of $4,985 and accumulated depreciation of gathering and compression systems of $968,682.

Depreciation is on a straight-line method using the estimated lives of the assets (3-15 years). Expenditures for maintenance and repairs are charged to expense.

**Debt issue costs**

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt on the straight-line method of amortization over the estimated life of the debt.

**Oil & Gas Properties**

We follow the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities.

Proved properties are amortized using the units of production method (UOP). Currently we only have operations in the United States of America. The UOP calculation multiplies the percentage of estimated proved reserves produced each quarter by the cost of these reserves. The amortization base in the UOP calculation includes the sum of proved property, net of accumulated depreciation, depletion and amortization (DD&A), estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs, less related salvage value.

The cost of unproved properties are excluded from the amortization calculation until it is determined whether or not proved reserves can be assigned to such properties or until development projects are placed into service. Geological and geophysical costs not associated with specific properties are recorded as proved property immediately. Unproved properties are reviewed for impairment quarterly.

Under the full-cost-method of accounting, the net book value of oil and gas properties, less deferred income taxes, may not exceed a calculated “ceiling.” The ceiling limitation is (a) the present value of future net revenues computed by applying current prices of oil & gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil & gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of 10 percent and assuming continuation of existing economic conditions *plus* (b) the cost of properties not being amortized *plus* (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized *less* (d) income tax effects related to differences between book and tax basis of properties. Future cash outflows associated with settling accrued retirement obligations are excluded from the calculation. Estimated future cash flows are calculated using end-of-period costs and an un-weighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months held flat for the life of the production, except where prices are defined by contractual arrangements.

Any excess of the net book value of proved oil and gas properties, less related deferred income taxes, over the ceiling is charged to expense and reflected as additional DD&A in the statement of operations. The ceiling calculation is performed quarterly. During the years ended December 31, 2014 and 2013 there were no impairments resulting from the quarterly ceiling tests.

Proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion (greater than 25%) of our reserve quantities are sold, in which case a gain or loss is recognized in income.

**Long-Lived Assets**

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value that is usually measured based on an estimate of future discounted cash flows.

**Asset Retirement Obligations**

The asset retirement obligation relates to the plug and abandonment costs when our wells are no longer useful. We determine the value of the liability by obtaining quotes for this service and estimate the increase we will face in the future. We then discount the future value based on an intrinsic interest rate that is appropriate for us. If costs rise more than what we have expected there could be additional charges in the future, however, we monitor the costs of the abandoned wells and we will adjust this liability if necessary.

**Major Purchasers**

For the years ended December 31, 2014, and 2013 we sold our produced crude oil to Coffeyville Resources, Plains Marketing, L.P., and Sunoco, Inc. on a month-to-month basis and we sold our produced natural gas to United Energy Trading and Western Operating Company.

**Marketable Securities Available for Sale**

The Company classifies its marketable equity securities as available-for-sale and they are carried at fair market value, with the unrealized gains and losses included in accumulated other comprehensive income and reported in stockholders’ equity. The difference between cost and market totals $552,589 for the years ended December 31, 2014 and 2013.

**Net Income Per Common Share**

Basic net income per share is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect, in periods in which they have a dilutive effect, the impact of common shares issuable upon exercise of stock options and warrants and conversion of convertible debt that are not deemed to be anti-dilutive. The dilutive effect of the outstanding stock options and warrants is computed using the treasury stock method.

For the year ended December 31, 2014, diluted net income per share did not include the effect of 231,332 shares of common stock issuable upon the exercise of outstanding stock options as their effect would be anti-dilutive.

For the year ended December 31, 2013, diluted net income per share did not include the effect of 172,833 shares of common stock issuable upon the exercise of outstanding stock options as their effect would be anti-dilutive.

**Reclassifications**

Certain reclassifications have been made to prior periods to conform to current presentations.

**Recent Accounting Pronouncements Applicable to the Company**

The Company does not believe there are any recently issued, but not yet effective; accounting standards that would have a significant impact on the Company’s financial position or results of operations.

**Note 2 - Equity Transactions**

**Stock transactions in fiscal year ended December 31, 2014**

In 2014, 7,707 shares were issued to employees of the Company as compensation. The value of those shares was $59,298. Also in 2014, 9,625 shares were issued and 17,500 shares are owed (but not issued) for professional services rendered on behalf of the Company. The value of those share was $175,356.

Effective after the close of trading in EnerJex common stock on May 30, 2014, the Company affected a 1-for-15 reverse stock split, by which each share of EnerJex common stock was reclassified, and changed into $1/15^{th}$ of a fully paid and non-assessable share of common stock. In lieu of fractions of a share, the Company paid to holders of fractions of a share cash equal to $11.25 per share, which was the minimum value designated in the amended and restated certificate of designations affecting the reverse stock split.

On June 16, 2014, we adopted the Amended and Restated Certificate of Designation modifying the terms of our then-existing Series A preferred stock. Concurrently with filing of that Amended and Restated Certificate of Designation, the holders of our existing Series A preferred stock exchanged each outstanding share of such existing Series A preferred stock for (i) a number of shares of our common stock into which such Series A preferred stock was then convertible immediately prior to the exchange (318,630 shares in the aggregate), and (ii) 112,658 shares of Series A preferred stock which was equal to the quotient determined by dividing (x) that portion of the holder's original Series A preferred stock purchase price that had not yet been paid in dividends, by (y) $23.75.

On June 20, 2014, we closed an underwritten initial public offering of 639,157 shares of our Series A preferred stock at a purchase price of $23.75 per share for gross proceeds of $15,179,938. Costs associated with the offering were $1,832,374 for net proceeds of $13,347,564.

Effective September 30, 2014 the Board of Directors approved the retirement of 383,333 shares in held in the Treasury. Accordingly $2,551,000 was reclassified to Paid-in capital.

**Stock transactions in fiscal year ended December 31, 2013**

We issued 6,000 shares at $7.50 per share to employees as compensation.

On September 30, 2013 the Company issued 2,755,168 shares to Black Raven Energy, Inc. shareholders in exchange for their shares of Black Raven Energy, Inc. common shares. (See Note 5).

**Option transactions**

Officers (including officers who are members of the Board of Directors), directors, employees and consultants are eligible to receive options under our stock option plans. We administer the stock option plans and we determine those persons to whom options will be granted, the number of options to be granted, the provisions applicable to each grant and the time periods during which the options may be exercised. No options may be granted more than ten years after the date of the adoption of the stock option plans.

Each option granted under the stock option plans will be exercisable for a term of not more than ten years after the date of grant. Certain other restrictions will apply in connection with the plans when some awards may be exercised. In the event of a change of control (as defined in the stock option plans), the vesting date on which all options outstanding under the stock option plans may first be exercised will be accelerated. Generally, all options terminate 90 days after a change of control.

**Stock Incentive Plan**

The Board of Directors approved the EnerJex Resources, Inc. Stock Option Plan on August 1, 2002 (the "2002-2003 Stock Option Plan"). Originally, the total number of options that could be granted under the 2002-2003 Stock Option Plan was not to exceed 26,666 shares. In September 2007 our stockholders approved a proposal to amend and restate the 2002-2003 Stock Option Plan to increase the number of shares issuable to 66,666. On October 14, 2008 our stockholders approved a proposal to amend and restate the 2002-2003 Stock Option Plan to (i) rename it the EnerJex Resources, Inc. Stock Incentive Plan (the "Stock Incentive Plan"), (ii) increase the maximum number of shares of our common stock that may be issued under the Stock Incentive Plan to 83,333, and (iii) add restricted stock as an eligible award that can be granted under the Stock Incentive Plan.

On December 31, 2010 we granted 60,000 options that vest ratably over a 48 month period and are exercisable at $6.00 per share to an Officer of the company. The term of the options is 5 years. The fair value of the options as calculated using the Black-Scholes model was $307,751. The amount recognized as expense in each of the years ended December 31, 2014 and 2013 was $76,938.

**2013 Stock Incentive Plan**

The Board and stockholders approved the adoption of the 2013 Stock Incentive Plan (“Plan”). The Plan reserves 333,300 shares of our common stock for the granting of options and issuance of restricted shares to our employees, officers, directors, and consultants. The Plan increases reserved shares annually based on plan provisions.

In 2013, we granted 119,133 options to employees. Thirty-three percent of these options vest one year after the date of the grant. The remaining options vest ratably each month over a two year period. The fair value of the option on the date of the grant calculated using the Black-Scholes model was $675,344 using the following weighted average assumptions: exercise price of $10.50 per share; common stock price of ranging from $7.95 to $8.40 per share; volatility ranging from 67% to 72%; term of three years; dividend yield of 0%; interest rate of .47%.

In 2014, we granted 2,367 options to employees. Thirty-three percent of these options vest one year after the date of the grant. The remaining options vest ratably each month over a two year period. The fair value of the option on the date of the grant calculated using the Black-Scholes model was $12,178 using the following weighted average assumptions: exercise price of $10.50 per share; common stock price of $7.95 per share; volatility of 72%; term of three years; dividend yield of 0%; interest rate of .47%.

We expensed $326,579 and $72,434 for the years ended December 31, 2014 and December 31, 2013 respectively for options granted. We also expensed $76,938 in each of the years ended December 31, 2014 and December 31, 2013 for options recorded as prepaid assets.

**Warrant Transactions**

On May 31, 2012, we granted 16,667 Warrants to a consultant for services to be performed over the next two years. Each warrant was exercisable until May 31, 2014. The fair value at the date of grant was calculated using the Black-Scholes model and totaled approximately $86,000. On January 3, 2013, we granted 20,000 Warrants to a consultant for services to be performed over the next year. The fair value at the date of grant was calculated using the Black-Scholes model and totaled approximately $41,000. In the fourth quarter of 2013 all 36,667 warrants were cancelled unexercised.

A summary of stock options and warrants is as follows:

| | Options | Weighted Ave. Exercise Price | Warrants | Weighted Ave. Exercise Price |
|---|---|---|---|---|
| Outstanding January 1, 2013 | 112,333 | $ 8.10 | 16,667 | $ 10.50 |
| Granted | 119,133 | 10.50 | 20,000 | 10.50 |
| Cancelled | (333) | (10.50) | (36,667) | (10.50) |
| Exercised | - | - | - | - |
| Outstanding December 31, 2013 | 231,133 | $ 9.36 | - | $ - |
| Granted | 2,367 | 10.50 | - | - |
| Cancelled | (2,168) | (10.50) | - | - |
| Exercised | - | - | - | - |
| Outstanding December 31, 2014 | 231,332 | $ 9.33 | - | $ - |

The number of options that were vested at December 31, 2014 was 150,843. The number of options that were not vested at December 31, 2014 was 80,489.

**Note 3 - Asset Retirement Obligation**

Our asset retirement obligations relate to the abandonment of oil and gas wells. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, inflation rates and credit adjusted risk-free interest rates. The following shows the changes in asset retirement obligations:

| | |
|---|---|
| Asset retirement obligations, January 1, 2013 | $ 1,336,151 |
| Liabilities acquired | 1,251,511 |
| Liabilities incurred during the period | 56,825 |
| Liabilities settled during the year | (96,465) |
| Accretion | 139,779 |
| Asset retirement obligations, December 31, 2013 | $ 2,687,801 |
| Liabilities incurred during the period | 65,385 |
| Liabilities settled during the year | (102,929) |
| Accretion | 255,836 |
| Asset retirement obligations, December 31, 2014 | $ 2,906,093 |

**Note 4 - Long-Term Debt**

**Senior Secured Credit Facility**

On October 3, 2011, the Company, DD Energy, Inc., EnerJex Kansas, Inc., Black Sable Energy, LLC and Working Interest, LLC ("Borrowers") entered into an Amended and Restated Credit Agreement with Texas Capital Bank, and other financial institutions and banks that may become a party to the Credit Agreement from time to time. The facilities provided under the Amended and Restated Credit Agreement are to be used to refinance Borrowers prior outstanding revolving loan facility with Bank, dated July 3, 2008, and for working capital and general corporate purposes.

At our option, loans under the facility will bear stated interest based on the Base Rate plus Base Rate Margin, or Floating Rate plus Floating Rate Margin (as those terms are defined in the Credit Agreement). The Base Rate will be, for any day, a fluctuating rate per annum equal to the higher of (a) the Federal Funds Rate plus 0.50% and (b) the Bank's prime rate. The Floating Rate shall mean, at Borrower's option, a per annum interest rate equal to (i) the Eurodollar Rate plus Eurodollar Margin, or (ii) the Base Rate plus Base Rate Margin (as those terms are defined in the Amended and Restated Credit Agreement). Eurodollar borrowings may be for one, two, three, or six months, as selected by the Borrowers. The margins for all loans are based on a pricing grid ranging from 0.00% to 0.75% for the Base Rate Margin and 2.25% to 3.00% for the Floating Rate Margin based on the Company's Borrowing Base Utilization Percentage (as defined in the Amended and Restated Credit Agreement).

We entered into a First Amendment to Amended and Restated Credit Agreement and Second Amended and Restated Promissory Note in the amount of $50,000,000 with Texas Capital Bank, which closed on December 15, 2011. The Amendment reflects the addition of Rantoul Partners, as an additional Borrower and adds as additional security for the loans the assets held by Rantoul Partners.

On August 31, 2012, we entered into a Second Amendment to Amended and Restated Credit Agreement with Texas Capital Bank. The Second Amendment: (i) increased the borrowing base to $7,000,000 (ii) reduced the minimum interest rate to 3.75% and (iii) added additional new leases as collateral for the loan.

On November 2, 2012, we entered into a Third Amendment to Amended and Restated Credit Agreement with Texas Capital Bank. The Third Amendment (i) increased the borrowing base to $12,150,000 and (ii) clarified certain continuing covenants and provided a limited waiver of compliance with one of the covenants so clarified for the fiscal quarter ended December 31, 2011.

On January 24, 2013, we entered into a Fourth Amendment to Amended and Restated Credit Agreement, which was made effective as of December 31, 2012 with Texas Capital Bank. The Fourth Amendment reflects the following changes: (i) the Bank consented to the restructuring transactions related to the dissolution of Rantoul Partners, and (ii) the Bank terminated a Limited Guaranty, as defined in the Credit Agreement, executed by Rantoul Partners in favor of the Bank

On April 16, 2013, the Bank increased our borrowing base to $19.5 million.

On September 30, 2013, the Company entered into a Fifth Amendment to the Amended and Restated Credit Agreement. The Fifth Amendment reflects the following changes: (i) an expanded principal commitment amount of the Bank to $100,000,000; (ii) increased the Borrowing Base to $38,000,000; (iii) added Black Raven Energy, Inc. to the Credit Agreement as borrower parties; (iv) added certain collateral and security interests in favor of the Bank; and (v) reduced the Company’s current interest rate to 3.30%.

On November 19, 2013, we entered into a Sixth Amendment to the Amended and Restated Credit Agreement. The Sixth Amendment reflects the following changes: (i) the addition of Iberia Bank as a participant in our credit facility, and (ii) a technical correction to our covenant calculations.

On May 22, 2014, we entered into a Seventh Amendment to the Amended and Restated Credit Agreement. The Seventh Amendment reflects the Bank’s consent to our issuance of up to 850,000 shares of our 10% Series A Cumulative Redeemable Perpetual Preferred Stock.

On August 15, 2014 we entered into an Eighth Amendment to the Amended and Restated Credit Agreement. The Eighth Amendment reflects the following changes: (i) the borrowing base was increased from $38 million to $40 million, and (ii) the maturity of the facility was extended by three years to October 3, 2018.

Our Current borrowing base is $40 million, of which we had borrowed $23.0 million as of December 31, 2014. We intend to conduct an additional borrowing base review in the third quarter of 2015. For the year ended December 31, 2014 the interest rate was 3.3 %. This facility expires on October 3, 2018.

We financed the purchase of vehicles through a bank. The notes are for four years and the vehicles collateralize these notes. The long term balance on the notes at December 31, 2014 was $11,660.

**Note 5 - Merger**

On July 23, 2013, EnerJex, BRE Merger Sub, Inc., a Delaware corporation and a wholly owned subsidiary of EnerJex (Merger Sub), and Black Raven Energy, Inc., a Nevada corporation, entered into an agreement and plan of merger (Merger Agreement) pursuant to which Black Raven would be merged with and into Merger Sub and after which Black Raven would be a wholly owned subsidiary of EnerJex.

On September 27, 2013, the transactions contemplated by the Merger Agreement were successfully completed.

The following transactions were executed on September 27, 2013 per the terms of the Merger Agreement (i) shares of capital stock of Black Raven were converted into (a) cash totaling $207,067 and (b) 41,327,516 shares of EnerJex common stock, (ii) all options under the Black Raven option plan were cancelled, and (iii) all warrants or other rights to purchase shares of capital stock of Black Raven were converted into warrants to purchase EnerJex common stock. No fractional shares of EnerJex common stock were issued in connection with the Merger, and holders of Black Raven common stock were entitled to receive cash in lieu thereof. The board of directors and executive officers of EnerJex remained unchanged as a result of the closing of the Merger.

At closing of the transactions contemplated by the Merger Agreement, the previous stockholders of Black Raven owned approximately 38% of the outstanding voting stock of EnerJex and the previous stockholders of EnerJex owned approximately 62% of the outstanding voting stock of EnerJex.

The following selected pro forma condensed financial information of EnerJex and Black Raven combines the consolidated financial information of EnerJex for the twelve month period ended December 31, 2013 with the financial information of Black Raven for the twelve months ended December 31, 2013.

EnerJex and Black Raven present the unaudited pro forma condensed consolidated financial information for informational purposes only. The pro forma information is not necessarily indicative of what the combined company's financial position or results of operations actually would have been had EnerJex and Black Raven completed the merger on January 1, 2013. In addition the unaudited pro forma condensed consolidated financial information does not purport to project the future financial position or operating results of the combined company. The unaudited pro forma condensed consolidated financial information does not give effect to any potential cost savings or other operating efficiencies that could result from the merger. The unaudited pro forma condensed consolidated financial information is not adjusted for any merger related transaction costs or other non-recurring expenses.

The unaudited pro forma condensed consolidated financial information includes estimates of Black Raven had it accounted for its investments in oil and gas assets using the full cost method of accounting and not the successful efforts method of accounting. The unaudited pro forma consolidated financial information was prepared using the full cost method of accounting for oil and gas activities.

**Pro Forma Consolidated Combined Statements of Operations (Unaudited)**
**For the Year Ended December 31, 2013**

| | | |
|---|---|---|
| Revenues | $ | 14,362,000 |
| Income from operations | $ | 2,106,000 |
| Net income (loss) | $ | (141,700) |
| Net income (loss) per common share | $ | - |

**Note 6 - Related party transactions**

In the normal course of business we utilize the services of stockholders who perform work for us at normal business rates.

**Note 7 - Commitments and Contingencies**

Rent expense for the years ended December 31, 2014 and 2013 was approximately $159,000 and $185,000 respectively. Future non-cancellable minimum lease payments are approximately $150,000 for 2015, $147,000 for 2016, $145,000 for 2017, $91,000 for 2018 and $77,000 for 2019. We received rental income from sub rentals of $37,000 in 2013.

We, as a lessee and operator of oil and gas properties, are subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject to the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. As of December 31, 2014, we have no reserve for environmental remediation and are not aware of any environmental claims.

As of December 31, 2014, the Company has an outstanding irrevocable letter of credit in the amount of $50,000 issued in favor of the Texas Railroad Commission. This letter of credit is required by the Commission by all companies operating in the state in accordance with limits prescribed by the Texas Railroad Commission.

**Note 8 - Income Taxes**

There was no current or deferred income tax expense (benefit) for the years ended December 31, 2014 and December 31, 2013.

The following table sets forth a reconciliation of the provision for income taxes to the statutory federal rate:

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Statutory tax rate | 35.0% | 34.0% |
| State tax rate, net of federal tax | 1.37% | 1.37% |
| Other permanent items | 0.05% | 0.59% |
| Change in valuation allowance | (36.42)% | (35.96)% |
| Effective tax rate | 0.0% | 0.0% |

Significant components of the deferred tax assets and liabilities are as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Non-current deferred tax asset: | | |
| Oil and gas costs and long-lived assets | $ (1,038,092) | $ (739,919) |
| Derivative instruments | (1,717,301) | 921,771 |
| Net operating loss carry-forward | 25,915,146 | 9,138,048 |
| Valuation allowance | (23,159,753) | (9,319,900) |
| Net deferred tax asset (liability) | $ - | $ - |

At December 31, 2014, we have a net operating loss carry forward of approximately $76 million expiring in 2021-2035 that is subject to certain limitations on an annual basis. A valuation allowance has been established against net operating losses where it is more likely than not that such losses will expire before they are utilized.

The Company incurred a change of control as defined by the Internal Revenue Code. Accordingly, the rules will limit the utilization of the Company's net operating losses. The limitation is determined by multiplying the value of the stock immediately before the ownership change by the applicable long-term exempt rate. It is estimated that approximately $40.9 million of net operating losses may be subject to an annual limitation. Any unused annual limitation may be carried over to later years. The amount of the limitation may under certain circumstances be increased by the built-in gains in assets held by the Company at the time of the change that are recognized in the five-year period after the change.

**Note 9 - Fair Value Measurements**

We hold certain financial assets which are required to be measured at fair value on a recurring basis in accordance with the Statement of Financial Accounting Standard No. 157, *"Fair Value Measurements"* ("ASC Topic 820-10"). ASC Topic 820-10 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). ASC Topic 820-10 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants on the measurement date. A fair value measurement assumes that the transaction to sell the asset or transfer the liability occurs in the principal market for the asset or liability. The three levels of the fair value hierarchy under ASC Topic 820-10 are described below:

Level 1. Valuations based on quoted prices in active markets for identical assets or liabilities that an entity has the ability to access. We believe receivables, payables and our debt approximate fair value at December 31, 2014.

Level 2. Valuations based on quoted prices for similar assets or liabilities, quoted prices for identical assets or liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable data for substantially the full term of the assets or liabilities. We consider the derivative liability to be Level 2. We determine the fair value of the derivative liability utilizing various inputs, including NYMEX price quotations and contract terms.

Level 3. Valuations based on inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. We consider the marketable securities to be a Level 3. Our derivative instruments consist of fixed price commodity swaps.

| | Fair Value Measurement | | |
|---|---|---|---|
| | Level 1 | Level 2 | Level 3 |
| Crude oil contracts | $ - | $ 4,721,751 | $ - |
| Marketable securities | $ - | $ - | $ 1,018,573 |

**Note 10 - Derivative Instruments**

We have entered into certain derivative or physical arrangements with respect to portions of our crude oil production to reduce our sensitivity to volatile commodity prices and/or to meet hedging requirements under our Credit Facility. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil. Moreover, our derivative arrangements apply only to a portion of our production.

We have an Intercreditor Agreement in place between the Company; our counterparties, BP Corporation North America, Inc. and Cargill Incorporated and our agent, Texas Capital Bank, N.A., which allows Texas Capital Bank to also act as agent for the counterparties for the purpose of holding and enforcing any liens or security interests resulting from our derivative arrangements. Therefore, we generally are not required to post additional collateral, including cash.

The following derivative contracts were in place at December 31, 2014:

| | Term | Monthly Volumes [1] | Price/Bbl | Fair Value |
|---|---|---|---|---|
| Deferred premium put | 1/16-6/16 | 9,000Bbls | $ 85.00 | $ 985,747 |
| Crude oil swap | 1/15-12/15 | 5,800Bbls | $ 88.55 | 2,212,584 |
| Crude oil swap | 9/13-12/14 | 3,000Bbls | $ 95.15 | 107,580 |
| Crude oil swap | 7/11-12/15 | 2,942Bbls | $ 83.70 | 1,024,763 |
| Crude oil swap | 1/14-12/14 | 1,900Bbls | $ 96.00 | 69,749 |
| Crude oil swap | 7/12-12/15 | 1,092Bbls | $ 76.74 | 278,139 |
| Crude oil swap | 1/14-12/14 | 1,395Bbls | $ 90.25 | 43,189 |
| | | | | $ 4,721,751 |

(1) Monthly volumes are the weighted average throughout the period.

The total fair value of derivative contracts is shown in both current and non-current assets and liabilities on the balance sheet. We recorded gains on the derivative contracts for the year ended December 31, 2014 of $4,993,262 and losses for the year ended December 31, 2013 of $740,456.

**Note 11 – Net Income Per Common Share**

The Company reports earnings per share in accordance with ASC Topic 260-10, *"Earnings per Share."* Basic earnings per share is computed by dividing income available to common shareholders by the weighted average number of common shares available. Diluted earnings per share is computed similar to basic earnings per share except that the denominator is increased to include the number of additional common shares that would have been outstanding if the potential common shares had been issued and if the additional common shares were dilutive.

**Note 12 - Subsequent Events**

On March 13, 2015 the Company issued in a registered offering 763,547 registered shares of its common stock together with 1,242.17099 shares of its newly designated Series B Convertible Preferred Stock (the "Preferred Stock") convertible into 709,812 shares of common stock. We also issued in an unregistered offering, 521.62076 shares of Preferred Stock convertible into 298,069 shares of common stock, and warrants to purchase 1,771,428 shares of its common stock. The shareholder's ability to convert a portion of the Preferred Stock and to exercise the warrant are restricted: (i) prior to the Company obtaining approval of the offering by its shareholders, which we expect to obtain before May 31, 2015, and (ii) pursuant to customary "blocker" provisions restricting the investor's ownership to 9.99% of our outstanding common stock.

The Preferred Stock has a liquidation preference of $1,000 per share, and will be convertible at the option of the shareholder at a conversion ratio equal to approximately 571 shares of common stock for each one (1) share of Preferred Stock, subject to customary adjustments and anti-dilution price protection. Dividends are payable on the shares of Preferred Stock only if and to the extent that dividends are payable on the common stock into which the Preferred Stock is convertible. The Preferred Stock has no maturity date and can be redeemed by the Company beginning twelve months after the closing of the offering or upon a change of control. Each warrant will be exercisable for one share of common stock, for a period of five years beginning six months after March 13, 2015, at a cash exercise price of $2.75 per share, and may be exercised on a cashless basis after that six-month period if no effective registration statement covers the warrant shares by that time.

On January 15, 2015, 52,000 options were issued to employees.

**Note 13 - Supplemental Oil and gas Reserve Information (Unaudited)**

**Results of operations from oil and gas producing activities**

The following table shows the results of operations from the Company's oil and gas producing activities. Results of operations from these activities are determined using historical revenues, production costs and depreciation and depletion. The results of operations from the Company's oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest income and interest expense. Income tax expense was determined by applying the statutory rates to pretax operating results.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Production revenues | $ 14,293,368 | $ 10,942,270 |
| Production costs | (6,762,248) | (4,095,850) |
| Depletion and depreciation | (3,259,442) | (1,691,008) |
| Income tax | (1,495,087) | (1,752,840) |
| Results of operations for producing activities | $ 2,776,591 | $ 3,402,572 |

**Capitalized costs**

The following table summarizes the Company's capitalized costs of oil and gas properties.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Properties subject to amortization | $ 78,090,619 | $ 71,917,308 |
| Accumulated depletion | (13,827,347) | (10,567,905) |
| Net capitalized costs | $ 64,263,272 | $ 61,349,403 |

**Cost incurred in property acquisition, exploration and development activities**

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Acquisition of properties | $ 1,017,698 | $ 124,028 |
| Exploration costs | - | - |
| Development costs | 6,078,167 | 7,484,419 |
| Net capitalized costs | $ 7,095,865 | $ 7,608,447 |

**Estimated quantities of proved reserves**

Our ownership interests in estimated quantities of proved oil and gas reserves and changes in net proved reserves all of which are located in the United States are summarized below. Proved reserves are estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those that are expected to be recovered through existing wells with existing equipment and operating methods. Reserves are stated in barrels of oil equivalent. Geological and engineering estimates by MHA Petroleum Consultants, LLC of proved oil and gas reserves at one point in time are highly interpretive, inherently imprecise and subject to ongoing revisions that may be substantial in amount. Although every reasonable effort is made to ensure that the reserve estimates are accurate, by their nature reserve estimates are generally less precise than other estimates presented in connection with financial statement disclosures.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Proved reserves (BOE): | | |
| Beginning | 5,804,600 | 2,927,000 |
| Revisions of previous estimates | (1,198,754) | 141,600 |
| Purchase of minerals in place | 2,234 | 2,685,517 |
| Extension and discoveries | 2,226 | 175,917 |
| Sale of minerals in place | - | (4,800) |
| Production | (210,126) | (120,634) |
| Ending | 4,400,180 | 5,804,600 |

Proved developed reserves at December 31, 2014 consisted of 77% oil and 23% natural gas and totaled 3,048.3 MBOEs. Proved developed reserves for December 31, 2013 consisted of 83% oil and 17% natural gas and totaled 3,824.9 MBOEs. Proved undeveloped reserves for December 31, 2014 were 1,351.9 MBOEs. Proved undeveloped reserves at December 31, 2013 were 1,979.9 MBOEs.

**Standardized measure of discounted future net cash flows**

The standardized measure of discounted future net cash flows from our proved reserves for the periods presented in the financial statements is summarized below.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Future production revenue | $ 282,557,900 | $ 413,965,250 |
| Future production costs | (101,119,500) | (122,957,721) |
| Future development costs | (13,736,500) | (20,017,885) |
| Future cash flows before income tax | 167,701,900 | 270,989,644 |
| Future income taxes | (4,211,005) | (56,111,563) |
| Future net cash flows | 163,490,895 | 214,878,081 |
| 10% annual discount for estimating of future cash flows | (100,787,044) | (133,430,425) |
| Standardized measure of discounted net cash flows | $ 62,703,851 | $ 81,447,656 |

**Changes in standardized measure of discounted future net cash flows**

The following is a summary of a standardized measure of discounted net future cash flows related to the Company's proved oil and gas reserves. The information presented is based on a calculation of estimated proved reserves using discounted cash flows based on the 12-month average price for oil and gas calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period. The additions to estimated proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant.

| | Year Ended December 31, 2014 | Year Ended December 31, 2013 |
|---|---|---|
| Balance beginning of year | $ 81,447,656 | $ 48,872,561 |
| Sales, net of production costs | (7,531,119) | (6,846,420) |
| Net change in pricing and production costs | (19,087,068) | (11,143,669) |
| Net change in future estimated development costs | 6,281,385 | (2,281,285) |
| Purchase of minerals in place | 190,502 | 32,687,100 |
| Extensions and discoveries | 35,203 | 3,342,922 |
| Sale of minerals in place | - | (37,375) |
| Revisions | (25,498,141) | 1,357,734 |
| Accretion of discount | 27,098,964 | 16,563,800 |
| Change in income tax | (233,531) | (1,067,712) |
| Balance end of year | $ 62,703,851 | $ 81,447,656 |