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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, 2013
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 **Suite 508** **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

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 $14 million based on a share value of $0.51.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 109,254,045 shares of common stock, $0.001 par value, outstanding on March 24, 2014.

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., DD Energy, Inc., Black Sable Energy, LLC, Rantoul Partners, 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 DD Energy, Inc., Black Sable Energy, LLC, Working Interest, LLC, EnerJex Kansas, Inc., Black Raven Energy, Inc., and in Rantoul Partners in which we held a 75% general partner interest and which we dissolved as of December 31, 2012.

Significant Developments in 2013

The following briefly describes our most significant corporate developments occurring in 2013:

- On January 24, 2013, the Company entered into a Fourth Amendment to the Amended and Restated Credit Agreement, which was made effective as of December 31, 2012 with Texas Capital Bank, N.A. (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 May 16, 2013, the Company sold two oil and gas leases in non-core operating areas for $439,975 of net proceeds.

- On June 6, 2013, the Board of Directors of the Company authorized the increase in the board size from four to five directors, and appointed a new member, Richard E. Menchaca, effective immediately, to fill the vacancy. Mr. Menchaca serves as a member on the Audit and the Governance, Compensation and Nominating Committees of the Board of Directors.

- On July 15, 2013, the Company's Audit Committee approved the engagement of L.L. Bradford & Company, LLC (L.L. Bradford) as its independent registered public accounting firm for the Company's fiscal year ending December 31, 2013. Concurrent with its appointment of L.L. Bradford & Company, LLC, the Audit Committee dismissed Weaver Martin & Samyn, LLC, which served as the Company's independent registered public accountant for the fiscal years ended December 31, 2012, and December 31, 2011. There were no disagreements between the Company and Weaver Martin & Samyn, LLC on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

- 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. ("Black Raven"), 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.

  The following transactions were executed on September 27, 2013 pursuant to 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. The warrants expired December 31, 2013. 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.

- 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 October 1, 2013, we appointed David L. Kunovic to the position of Executive Vice President, Exploration.

- We previously filed a petition seeking recovery of damages arising from breach of contract, legal malpractice, breach of fiduciary duty and fraud in the Circuit Court of Jackson County, Missouri against attorneys Jeffrey T. Haughey, Robert K. Green, and the law firm Husch Blackwell LLP f/k/a Husch Blackwell Sanders, LLC. The petition in this action, *EnerJex Resources, Inc., v. Haughey, et al.*, alleges, among other things, that the defendants violated their fiduciary duties and defrauded us in connection with our stock offering in 2008.

  The petition alleges economic loss of approximately $50 million and demands judgment for unspecified actual and punitive damages together with repayment of $484,473 in legal fees paid by EnerJex. At the time the petition was filed, we estimated our economic loss of approximately $50 million by conducting an analysis that considered a number of factors, including the loss of at least $25 million of gross proceeds we would have received in the failed 2008 stock offering, the loss of the value we could have created had we been able to utilize the proceeds from the stock offering to execute our business plan in the 2008 economic environment, and the loss of market value for our common stock.

  A trial to hear a portion of this case in the 16th Circuit Court of Jackson County, Missouri, began on December 2, 2013. In that trial, based on its rulings on written motions, the court disallowed our claims for actual and consequential damages for breach of contract and legal malpractice against the defendants. On December 19, 2013, the Company reached an agreement with the defendants to settle our claims for breach of fiduciary duty and fraud in return for (i) the defendants paying to us the sum of $500,000, which was paid to us in January 2014, and (ii) dismissal of the defendants' counterclaim of $492,134 and interest on that amount, which was removed from our balance sheet and is not reflected as a liability as of December 31, 2013. Our financial statements reflect the litigation costs we have incurred to date.

  In entering into this settlement, the defendants have not admitted liability on any matter related to the claims in the litigation. As part of this settlement, we are now free to appeal the court's rulings and request from the appellate court authorization to pursue our claims for actual and consequential damages with respect to our claims alleging breach of contract and legal malpractice against the defendants. There can be no assurance of the outcome of the appellate process, including whether the appellate court will allow us to seek actual and consequential damages for breach of contract and legal malpractice and breach of fiduciary duty, as well as what amount of damages, if any, we may recover.

  Any additional monetary award resulting from a settlement of this litigation that is reached for our benefit in an amount that exceeds our total costs of litigation shall be subject to a contingency fee for the benefit of our attorneys. There can be no assurance of the outcome of this litigation, including whether and in what amount EnerJex may recover damages.

- In December 2013, the Company expanded its' acreage in the Mississippian Project. The expansion acreage is located in Woodson County, Kansas, in close proximity to EnerJex's existing operations. The expansion acreage includes a 90% working interest in 1,280 acres located adjacent to acreage that the Company successfully developed in 2012 and 2013, which is in the early stage of secondary recovery. The Company earned this acreage after achieving certain development milestones related to the adjacent acreage, and it expects to earn another 320 acres in this area after achieving additional development milestones.

- 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 Participation Agreement, EnerJex received a 70% working interest in the Golden Project, consisting of approximately 2,330 gross acres. As consideration for entering into the Participation Agreement, the Company agreed to pay $79,555 in cash and agreed to pay 100% of all capital expenditures, up to a maximum of $320,445, associated with drilling and completing three new wells in the Golden Project prior to June 30, 2014.

- During 2013, we drilled 22 oil wells and 21 secondary recovery water injection wells in our Mississippian Project and 26 oil wells and 24 secondary recovery water injection wells in our Cherokee Project. Subsequent to the merger with Black Raven Energy, Inc., we recompleted four oil wells in our Adena Field Project.

- During 2013, the Company entered into transactions in which it hedged an additional 75,000 barrels (205 bopd) of crude oil in 2014. Approximately 16,000 barrels were hedged at a price of $90.25 per barrel, 36,000 barrels were hedged at a price of $95.15 per barrel and approximately 23,000 barrels were hedged at a price of $96.00 per barrel. We also entered into a transaction to hedge approximately 70,000 barrels (190 bopd) of crude oil in 2015 at a price of $88.55 per barrel.

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, 2013 were 5.8 million barrels of oil equivalents (BOE), of which 77% was oil. Of the 5.8 million BOE of total proved reserves, approximately 49% are classified as proved developed producing, approximately 17% are classified as proved developed non-producing, and approximately 34% are classified as proved undeveloped.

The total PV10 (present value) of our proved reserves as of December 31, 2013 was approximately $102 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, 2013.

Our Colorado Properties

The table below summarizes our current Colorado and Nebraska acreage by project name as of December 31, 2013.

Project Name	Developed Acreage (1)		Undeveloped Acreage		Total Acreage	
	Gross	**Net (2)**	**Gross**	**Net (2)**	**Gross**	**Net (2)**
Adena Field	18,760	18,760	-	-	18,760	18,760
Niobrara - Colorado (3)	34,307	33,866	15,459	14,453	49,766	48,319
Niobrara - Nebraska	-	-	9,525	9,364	9,525	9,364
Total	**53,067**	**52,626**	**24,984**	**23,817**	**78,051**	**76,443**

(1) Developed acreage includes all acreage that was held by production as of December 31, 2013.
(2) Net acreage is based on our net working interest as of December 31, 2013.
(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, 2013. 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 only a small number of wells have been produced since that time.

Approximately 124 wells on our acreage are currently shut-in or temporarily abandoned. We have used new data, analysis and engineering to initially identify approximately 90 wells to be reactivated in the J-Sand formation or recompleted uphole in the D-Sand formation. We intend to reactive 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, 2013, the Adena Field Project was producing approximately 150 gross barrels of oil per day from 10 J-Sand wells and 9 D-Sand wells at a depth of approximately 5,500 feet. In addition, multiple wells capable of producing natural gas were shut-in at the end of 2013 pending completion of a new purchase contract that was completed in early 2014. Multiple wells were also in various stages of reactivation and recompletion as of December 31, 2013. We intend to aggressively pursue our reactivation and recompletion strategy in 2014.

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 $28 million).

Niobrara – Colorado & Nebraska

Our Niobrara Project is located in the northeastern portion of the D-J Basin, where we owned a 97% working interest in approximately 59,291 gross acres as of December 31, 2013. Our acreage is located in Phillips and Sedgwick Counties, Colorado, and Perkins County, Nebraska.

Approximately 34,000 acres in this project are held by production and leases on approximately 17,500 acres expire after 2015. As of December 31, 2013, 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, 2013, we produced approximately 250 net mcf of natural gas per day from the Niobrara formation at a depth of approximately 2,500 feet. The majority of this production was attributable to our overriding royalty interest in the wells that are operated by Atlas Resources, LLC.

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. Operators are targeting numerous potential 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 resource plays under all of our current acreage position.

Other

We own an average working interest of 9% in 1,011 gross acres located in the Homestead Draw field in Wyoming. As of December 31, 2013, these properties were producing approximately 600 gross mcf of natural gas per day.

Our Kansas Properties

The table below summarizes our current Kansas acreage by project name as of December 31, 2013.

Project Name	Developed Acreage(1)		Undeveloped Acreage		Total Acreage	
	Gross	**Net (2)**	**Gross**	**Net (2)**	**Gross**	**Net (2)**
Mississippian Project	4,680	4,084	1,690	1,183	6,370	5,267
Cherokee Project	2,015	1,498	7,774	6,904	9,789	8,402
Other	584	292	-	-	584	292
Total	**7,279**	**5,874**	**9,464**	**8,087**	**16,743**	**13,961**

(1) Developed acreage includes all acreage that was held by production as of December 31, 2013.
(2) Net acreage is based on our net working interest as of December 31, 2013.

Mississippian Project

Our Mississippian Project is located in Woodson and Greenwood Counties in Southeast Kansas, where we owned a 90% working interest in 4,040 gross acres and a 70% working interest in 2,330 gross acres as of December 31, 2013. 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, and both wells were awaiting completion as of March 15, 2014.

As of December 31, 2013, our Mississippian Project was producing approximately 200 gross barrels of oil per day from the Mississippian formation at a depth of approximately 1,700 feet. We drilled and completed 22 new oil wells and 21 new water injection wells in this project during 2013. Water injection from some new injector wellbores commenced in late 2012, and new water injection operations were initiated throughout 2013 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 2014 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 9,789 gross acres as of December 31, 2013. As of December 31, 2013, approximately 21% of the gross leased acres in the Cherokee Project were held by production, and numerous low risk development opportunities exist on acreage that is currently undeveloped. A majority of the undeveloped leases have between two and five years (terms refer to leases with contractual extension options) remaining in the primary term and we are not currently facing any material lease expiration issues. As of December 31, 2013, our Cherokee Project was producing approximately 250 gross barrels of oil per day from the Squirrel formation at a depth of approximately 600 feet. We drilled 26 new oil wells and 24 new water injection wells during 2013.

Other

We own a 50% working interest in 584 gross acres located in Allen County Kansas. As of December 31, 2013, these properties were producing less than 10 gross barrels of oil per day.

Our Texas Properties

The table below summarizes our current Texas acreage by project name as of December 31, 2013.

Project Name	Developed Acreage(1)		Undeveloped Acreage		Total Acreage	
	Gross	**Net (2)**	**Gross**	**Net (2)**	**Gross**	**Net (2)**
El Toro Project	458	183	-	-	458	183
Lonesome Dove Project(3)	-	-	2,372	1,186	2,372	1,186
Total	**458**	**183**	**2,372**	**1,186**	**2,830**	**1,369**

(1) Developed acreage includes all acreage that was held by production as of December 31, 2013.
(2) Net acreage is based on our net working interest as of December 31, 2013.
(3) Undeveloped acreage includes a 50% working interest in depths through the Taylor Sand formation and a 10% working interest in depths below the Taylor Sand.

El Toro Project

Our El Toro Project is located in Atascosa and Frio Counties in South Texas. As of December 31, 2013, we owned a 40% working interest in 458 gross acres. As of December 31, 2013, this project was producing approximately 30 gross barrels of oil per day from the Olmos formation at a depth of approximately 4,500 feet.

We have completed 12 wells in the El Toro Project since 2009. While petro-physical data obtained from these wells has been consistent across the project acreage, production results have been inconsistent. The 3 most recent wells completed in this project have been successful, although the costs and time lag associated with drilling and completing them significantly exceeded our expectations. This is a direct result of the high demand and limited supply of services and equipment available in the El Toro Project area due to the Eagle Ford Shale play. As a result of increasing costs in this area, we did not drill any new wells in this project in 2013 and decided to focus 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 during 2014.

Lonesome Dove Project

Our Lonesome Dove Project is located in Lee County in South Texas. As of December 31, 2013, we owned working interests ranging from 10% to 50% in 2,372 gross acres. Our working interests under this acreage are separated by depth. We own approximately 50% of the gross acreage in horizons above approximately 4,500 feet, and we own a 10% working interest in the gross acreage in horizons below approximately 4,500 feet. We have an agreement with the majority owner of the deep rights wherein we would receive a 15% carried working interest in the first deep well drilled on this acreage at no cost to us. Deeper prospective horizons underlying this acreage include the Eagle Ford Shale, the Austin Chalk formation, the Buda formation, and the Pearsall Shale formation. Lease expirations in this project for the vast majority of the acreage range from 2017 to 2018.

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 in part 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, 2013 and the year ended December 31, 2012.

Drilling Activity

	Gross Wells			Net Wells [1]		
Fiscal Year	Total	Successful	Dry	Total	Successful	Dry
2012 - Exploratory	2	-	2	1.8	-	1.8
2013 - Exploratory	-	-	-	-	-	-
2012 - Development	227	226	1	172.6	171.7	0.9
2013 - Development	93	93	-	75.9	75.9	-

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

The following table sets forth the results of our reactivation and recompletion activities during the fourth quarter ended December 31, 2013 following our acquisition of Black Raven Energy, Inc.

Drilling Activity - Recompletion

	Gross Wells		Net Wells[1]	
Fiscal Year	Total	Successful	Total	Successful
2013 - Recompletion	4	4	4	4

(1) Net wells are based on our net working interest at the end of 2013.

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, 2013 and 2012, the average sales prices, average production costs and direct lifting costs per unit of production.

	Year Ended December 31, 2013	Year Ended December 31, 2012
Net Production		
Barrels of Oil Equivalent	120,634	96,842
Average Sales Prices per BOE	$ 90.71	$ 87.74
Average Production Cost per BOE[1]	$ 49.34	$ 47.95
Average Lifting Costs per BOE[2]	$ 33.95	$ 32.03

(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, 2013 and 2012. 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, 2013	**Year Ended December 31, 2012**
Production revenues	$ 10,942,270	$ 8,496,519
Production costs	(4,095,850)	(3,102,321)
Depreciation, depletion and amortization	(1,691,008)	(1,541,069)
Results of operations for producing activities	$ 5,155,412	$ 3,853,129

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, 2013.

	Active	
Project	**Gross**	**Net** [(1)]
Crude Oil		
El Toro Project	12	4.8
Mississippian Project	216	194.4
Cherokee Project	596	443.2
Adena Field Project	38	38.0
Other	37	32.6
Total Oil	899	713.0
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, 2013.

Reserves

Proved Reserves

The estimated total PV10 (present value) of our proved reserves as of December 31, 2013 was $102.4 million, compared to $60.8 million as of December 31, 2012. Our total net proved oil and gas reserves as of December 31, 2013 were 5.8 million BOE (77% oil), compared to 2.9 million BOE as of December 31, 2012. Of the 5.8 million net BOE of total proved reserves at December 31, 2013, approximately 49% are classified as proved developed producing, approximately 17% are classified as proved developed non-producing, and approximately 34% are classified as proved undeveloped. See "Glossary" on page 17 for our definition of PV10.

The estimated PV10 of the 5.8 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, 2013

Proved Reserves Category	Gross BOE	Net BOE [(1)]	PV10 [(2)] (before tax)
Proved, Developed	5,801,000	3,824,800	74,234,300
Proved, Undeveloped	2,664,700	1,979,800	28,177,500
Total Proved	8,465,700	5,804,600	102,411,800

(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, 2013.

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 2013, 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 and Western Operating Company on a month-to-month basis. 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 35 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 August 2016. We also have a field offices located at 2038 South Princeton St., Suite B, Ottawa, Kansas, 66067 and 1331 17th Street, Suite 350, Denver, Colorado 80202. 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.
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.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
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).
Gathering Line/System	Pipelines and other facilities that transport oil or gas from wells and bring it by separate and individual lines to a central delivery point for delivery into a transmission line or mainline.
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.
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.
Pooled Unit	A term frequently used interchangeably with "Unitization" but more properly used to denominate the bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules.
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 35 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.
Reservoir Pressure	The pressure at the face of the producing formation when the well is shut-in. It equals the shut-in pressure at the wellhead plus the weight of the column of oil and gas in the well.
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.
Shut-In Well	A well which is capable of producing but is not presently producing. Reasons for a well being shut-in may be lack of equipment, market or other.
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.

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

Our operations are affected by local, national and worldwide economic conditions. While the financial markets have generally strengthened over the last 5 years, bearish economic pressures remain as evidenced by a weak domestic labor market and the continued economic stimulus programs executed by the United States Federal Reserve. The consequences of uncertain economies and volatile financial and emerging markets may result in 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, Iran, North Korea or elsewhere, or the fear of such events, could exacerbate the volatility and disruption to the financial markets and economy. The situation in Iraq and Afghanistan, tension over Iran's nuclear program, and more recently the events in Libya**,** Ukraine and Syria highlight the instability of long-standing regimes which in turn has led to further uncertainty in the worldwide 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.

We have sustained losses in the past, and our future profitability is subject to many risks inherent in the oil and gas production industry.

Our prospects must be considered in light of the risks, expenses and difficulties frequently encountered in establishing and maintaining a business in the oil and gas industry. There is nothing conclusive at this time on which to base an assumption that our business operations will prove to be successful or that we will be able to operate profitably. Our future operating results will depend on many factors, including:

- the future prices of oil and gas;
- our ability to raise adequate capital;
- success of our development and exploration efforts;
- our ability to manage our operations cost effectively
- effects of our hedging strategies;
- demand for oil and gas;
- the level of our competition;
- our ability to attract and maintain key management, employees and operators;
- transportation and processing fees on our facilities;
- fuel conservation measures;
- alternate fuel requirements or advancements;
- government regulation and taxation;
- technical advances in fuel economy and energy generation devices; and
- our ability to efficiently explore, develop and produce sufficient quantities of marketable oil and gas in a highly competitive and speculative environment while maintaining and controlling costs.

To achieve profitable operations, we must, alone or with others, successfully execute on the factors stated above, along with continually developing ways to enhance our production efforts. Despite our best efforts, we may not be successful in our development efforts or obtain required regulatory approvals. There is a possibility that some of our wells may never produce oil and gas in sustainable or economic quantities.

We will need additional capital in the future to finance our planned growth, which we may not be able to raise or may be available only on terms unfavorable to us or our stockholders, which may result in our inability to fund our working capital requirements and harm our operational results.

We have and expect to continue to have substantial capital expenditure and working capital needs. We will need to rely on cash flow from operations and borrowings under our Credit Facility or raise additional cash to fund our operations, pay outstanding long-term debt, fund our anticipated reserve replacement needs and implement our growth strategy, or respond to competitive pressures and/or perceived opportunities, such as investment, acquisition, exploration, work-over and development activities.

If low oil and gas prices, operating difficulties, constrained capital sources or other factors, many of which are beyond our control, cause our revenues or cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to complete our development, production exploitation and exploration programs. If our resources or cash flows do not satisfy our operational needs, we will require additional financing, in addition to anticipated cash generated from our operations, to fund our planned growth. Additional financing might not be available on terms favorable to us, or at all. If adequate funds were not available or were not available on acceptable terms, our ability to fund our operations, take advantage of opportunities, develop or enhance our business or otherwise respond to competitive pressures would be significantly limited. In such a capital restricted situation, we may curtail our acquisition, drilling, development, and exploration activities or be forced to sell some of our assets on an untimely or unfavorable basis. Our current plans to address a drop in crude oil prices are to maintain hedges covering a portion of our expected future oil and gas production and to reduce both capital and operating expenditures to a level equal to or below cash flow from operations. However, our plans may not be successful in improving our results of operations and liquidity.

If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our stockholders would be reduced, and these newly issued securities might have rights, preferences or privileges senior to those of the securities held by our existing stockholders.

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 may materially and adversely affect our future business enough to 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 34% of our total proved reserves as of December 31, 2013 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, 2013 was $102.4 million, versus $60.8 million as of December 31, 2012. Of the 5.8 million BOE of total proved reserves, approximately 49% are classified as proved developed producing, approximately 17% are classified as proved developed non-producing, and approximately 34% 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, 2013 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 and gas production in Kansas are typically based on a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. In Texas, the prices that we receive for our oil production are currently based on a premium to NYMEX. In Colorado, the prices that we receive for our oil production are based upon a discount to NYMEX and the prices we receive for our natural gas production 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 Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually 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, 2013 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 December 31, 2015 for 245,000 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, 2013, we incurred realized and unrealized losses of approximately $740,000. 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, 2013 and 2012 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, may 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, 2013, we had $31,500,000 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 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) 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%.

As of December 31, 2013, we had total indebtedness of $31,500,000 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, 2013. 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, the terms of our Series A preferred stock, 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. In addition, we issued shares of Series A preferred stock, the terms of which require us to pay to the holders of those shares cumulative distributions of $4,779,460 before making any distributions to the holders of our common stock, unless we concurrently pay to holders of Series A preferred stock a dividend in like amount, on an as-converted-to-common stock basis. Those distributions to the holders of our Series A preferred stock are to be made from one-third of our available adjusted cash from operations, which is our net cash flow from operations less principal repaid to our lender. We presently are unsure how many calendar quarters of operations we will need in order to complete the preferential payments due to the holders of our Series A preferred stock. Even after we complete those distributions, we are likely to elect to retain and reinvest any available cash flow from operations, rather than funding dividend distributions to holders of our common stock.

There are a limited number of stockholders who have significant control over our common stock, allowing them to have significant influence over the outcome of all matters submitted to stockholders for approval, which may conflict with our interests and the interests of other stockholders.

Our directors, officers and principal stockholders (stockholders owning 10% or more of our common stock) and their affiliates beneficially owned approximately 81,817,257 shares or 74.9% of the outstanding shares of common stock, stock options, and derivatives that could have been converted to common stock at December 31, 2013, and 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 own 54.4% of our common stock and 50.6% 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 EnerJex Resources, Inc.

Our large stockholders may have interests that differ from those of other stockholders.

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, 2013, 54.4% of our common stock and 50.6% 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.

These stockholders' significant ownership of our voting stock may enable them to influence or effectively control us.

The holders of our outstanding shares of Series A Preferred Stock have dividend, conversion and other rights not shared with common stock holders.

As of March 24, 2014, we had 109,254,045 shares of our common stock issued and outstanding, as well as 4,779,460 shares of our Series A preferred stock issued and outstanding.

So long as any shares of Series A preferred stock are outstanding, we are required to declare dividends each calendar quarter in an aggregate amount equal to one-third of our adjusted net cash from operating activities reduced by any principal amount of debt repayment in such calendar quarter to our institutional lenders and any other secured creditors. This right restricts our ability to use a portion of our net cash flow for other purposes such as developing our assets, strategic acquisitions, and dividends, and has other important consequences to us, including the potential to adversely affect:

- our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our business strategy, or other general corporate purposes;
- our ability to use a portion of our operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to pay dividends;
- our ability to capitalize on business opportunities and to react to competitive pressures and changes in government regulation; and;
- our ability to, or increasing the cost of, refinancing our indebtedness

In addition, we cannot declare any dividends with regard to our common stock unless we concurrently pay to holders of Series A preferred stock a dividend in like amount, on an as-converted to common stock basis.

The Series A preferred stock is convertible into 4,779,460 shares of our common stock, and the Series A preferred stock, by its terms, shall convert into common stock on a one-to-one basis (subject to adjustment) once we have paid cumulative dividends of $4,779,460 with regard to such Series A preferred stock. To date, we have paid cumulative dividends of $1,247,950 to the holders of our Series A preferred stock, and the holders of those shares are entitled to receive an additional $3,075,221 of distributions prior to the conversion of those Series A preferred stock to common stock. The Series A preferred stock is convertible into common stock on a one-for-one basis, and upon conversion of the shares of Series A preferred stock, the common stock issued upon conversion would represent approximately 4.2% of our outstanding common stock. This would dilute the holdings of our existing common stockholders. In addition, the preferred stockholders vote together with our common stockholders, as a single class on an as-converted-to basis.

Furthermore, in the event of a liquidation of the Company, the holders of our Series A preferred stock would receive priority liquidation payments equal to the liquidation amount of the preferred stock before any distributions could be made to our common stockholders. The current total liquidation amount of our Series A preferred stock is approximately $3,075,221, so the preferred shareholders would be entitled to receive that amount before any distributions would be made to common stockholders.

Lastly, the preferred stockholders have the right, by majority vote of the shares of preferred stock, to generally approve any issuances by us of equity that is senior to or equal in rights to the preferred stock. Therefore, the preferred stockholders can effectively bar us from entering into a transaction which they feel is not in their best interests even if the transaction would otherwise be in the best interests of EnerJex and its common stockholders.

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 shares of preferred stock without asking for stockholder approval, which could cause your investment to be diluted.

Our 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.

Our common stock is traded on an illiquid market, making it difficult for investors to sell their shares.

Our common stock trades on the Over-the-Counter Bulletin Board (OTCBB) under the symbol "ENRJ," but trading volume has been minimal. Therefore, the market for our common stock is limited. The trading price of our common 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 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 common stock develops, the market price of our common 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 articles of incorporation, bylaws and Nevada Law contain provisions that could discourage an acquisition or change of control of us.

Our 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.

Because our common stock is deemed a low-priced "Penny" stock, an investment in our common stock should be considered high risk and subject to marketability restrictions.

Our common stock is currently deemed to be a penny stock, as defined in Rule 3a51-1 under the Securities Exchange Act, which may make it more difficult for investors to liquidate their investment even if and when a market develops for the common stock. Until the trading price of the common stock consistently trades above $5.00 per share, if ever, trading in the common stock may be subject to the penny stock rules of the Securities Exchange Act specified in rules 15g-1 through 15g-10. Those rules require broker-dealers, before effecting transactions in any penny stock, to:

- deliver to the customer, and obtain a written receipt for, a disclosure document;
- disclose certain price information about the stock;
- disclose the amount of compensation received by the broker-dealer or any associated person of the broker-dealer;
- send monthly statements to customers with market and price information about the penny stock; and
- in some circumstances, approve the purchaser's account under certain standards and deliver written statements to the customer with information specified in the rules.

Consequently, the penny stock rules may restrict the ability or willingness of broker-dealers to sell the common stock and may affect the ability of holders to sell their common stock in the secondary market and the price at which such holders can sell any such securities. These additional procedures could also limit our ability to raise additional capital in the future.

If we fail to remain current on our reporting requirements, we could be removed from the OTC Bulletin Board, which would limit the ability of broker-dealers to sell our securities and the ability of stockholders to sell their securities in the secondary market.

Companies trading on the OTCBB, such as us, must be reporting issuers under Section 12 of the Securities Exchange Act of 1934, as amended, and must be current in their reports under Section 13, in order to maintain price quotation privileges on the OTC Bulletin Board. More specifically, FINRA, which regulates trading on the OTC Bulletin Board, has enacted Rule 6530, which determines eligibility of issuers quoted on the OTCBB by requiring an issuer to be current in its filings with the Commission. Pursuant to Rule 6530(e), if we file our reports late with the Commission three times in a two-year period or our securities are removed from the OTCBB for failure to timely file twice in a two-year period then we will be ineligible for quotation on the OTCBB. As a result, the market liquidity for our securities could be severely adversely affected by limiting the ability of broker-dealers to sell our securities and the ability of stockholders to sell their securities in the secondary market.

FINRA sales practice requirements may limit a stockholder's ability to buy and sell our stock.

In addition to the "penny stock" rules described above, FINRA has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer's financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit your ability to buy and sell our stock and have an adverse effect on the market for our shares.

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.

We may become involved in various routine legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there are no material pending legal proceedings to which we are a party or to which any of our property is subject, except the legal proceedings disclosed below.

On January 23, 2012, we filed a petition seeking recovery of damages arising from breach of contract, legal malpractice, breach of fiduciary duty and fraud in the Circuit Court of Jackson County, Missouri against attorneys Jeffrey T. Haughey, Robert K. Green, and the law firm Husch Blackwell LLP f/k/a Husch Blackwell Sanders, LLC. The petition in this action, *EnerJex Resources, Inc., v. Haughey, et al.*, alleges, among other things, that the defendants violated their fiduciary duties and defrauded us in connection with our stock offering in 2008.

The petition alleges economic loss of approximately $50 million and demands judgment for unspecified actual and punitive damages together with repayment of $484,473 in legal fees paid by EnerJex. At the time the petition was filed, we estimated our economic loss of approximately $50 million by conducting an analysis that considered a number of factors, including the loss of at least $25 million of gross proceeds we would have received in the failed 2008 stock offering, the loss of the value we could have created had it been able to utilize the proceeds from the stock offering to execute its business plan in the 2008 economic environment, and the loss of market value for our common stock.

A trial to hear a portion of this case in the 16th Circuit Court of Jackson County, Missouri, began on December 2, 2013. In that trial, based on its rulings on written motions, the court disallowed our claims for actual and consequential damages for breach of contract and legal malpractice against the defendants. On December 19, 2013, the Company reached an agreement with the defendants to settle our claims for breach of fiduciary duty and fraud in return for (i) the defendants paying to us the sum of $500,000, which was paid to us in January 2014, and (ii) dismissal of the defendants' counterclaim of $492,134 and interest on that amount, which was removed from our balance sheet and is not reflected as a liability as of December 31, 2013. Our financial statements reflect the litigation costs that we have incurred to date.

In entering into this settlement, the defendants have not admitted liability on any matter related to the claims in the litigation. As part of this settlement, we are now free to appeal the court's rulings and request from the appellate court authorization to pursue our claims for actual and consequential damages with respect to our claims alleging breach of contract and legal malpractice against the defendants. There can be no assurance of the outcome of the appellate process, including whether the appellate court will allow us to seek actual and consequential damages for breach of contract and legal malpractice and breach of fiduciary duty, as well as what amount of damages, if any, we may recover.

Any additional monetary award resulting from a settlement of this litigation that is reached for our benefit in an amount that exceeds our total costs of litigation, shall be subject to a contingency fee for the benefit of our attorneys. There can be no assurance of the outcome of this litigation, including whether and in what amount EnerJex may recover damages.

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 currently trades on the OTCBB under the symbol "ENRJ." Our common stock has traded infrequently on the OTCBB, which limits our ability to locate accurate high and low bid prices for each quarter within the last two years. Therefore, the following table lists the quotations for the high and low sales prices of our common stock for the years ended December 31, 2012 and December 31, 2013. The quotations reflect inter-dealer prices without retail mark-up, markdown, or commissions and may not represent actual transactions. 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, 2012		
Quarter ended March 31, 2012	$ 0.90	$ 0.70
Quarter ended June 30, 2012	$ 0.78	$ 0.60
Quarter ended September 30, 2012	$ 0.74	$ 0.60
Quarter ended December 31, 2012	$ 0.73	$ 0.46
Year Ended December 31, 2013		
Quarter ended March 31, 2013	$ 0.69	$ 0.46
Quarter ended June 30, 2013	$ 0.69	$ 0.49
Quarter ended September 30, 2013	$ 0.75	$ 0.47
Quarter ended December 31, 2013	$ 0.63	$ 0.47

Holders

As of March 24, 2014, there were 1,403 holders of record of our common stock, and 15 holders of record of our Series A preferred stock.

Dividends

We have never paid or declared any cash dividends on our common stock. We are required by the terms of our Series A preferred stock to declare dividends each calendar quarter in an aggregate amount equal to one-third of our adjusted net cash from operating activities reduced by any principal amount of debt repayment in such calendar quarter to institutional lenders and other secured creditors. This right is senior to the rights of common stockholders to receive dividend payments. 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 preferred stock, if applicable at such time, and other factors our Board of Directors deems relevant.

Securities Authorized for Issuance under Equity Compensation Plans

See the section title “Equity Compensation Plan Information” under Item 12 in Part III of the Form 10-K.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

Effective November 30, 2012, we purchased 2,000,000 shares of stock from a stockholder for $323,035 in cash (including an option payment we previously made to the selling stockholder) and a note payable in the amount of $825,000 bearing an interest rate of 0.24% per year . The note was repaid in full on December 31, 2013.

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. Due to the merger with Black Raven Energy, Inc. on September 27, 2013 (see Note 5), only the results of operations for the fourth quarter are included for Black Raven.

	Year Ended December 31, 2013	Year Ended December 31, 2012	Difference
Oil & gas revenues[1]	$ 10,942,270	$ 8,469,519	$ 2,472,751
Average price per boe	$ 90.71	$ 87.74	$ 2.97
Expenses:			
Lease operating expenses[2]	$ 4,095,850	$ 3,102,321	$ 993,529
Depreciation, depletion and amortization [3]	1,691,008	1,541,069	149,939
Total production expenses	5,786,858	4,643,390	1,143,468
Professional fees[4]	1,071,740	1,483,720	(411,980)
Salaries[5]	1,432,081	601,533	830,548
Depreciation on other fixed assets	165,652	92,398	73,254

Administrative expenses[6]	798,457	808,836	(10,379)
Total expenses	$ 9,254,788	$ 7,629,877	$ 1,624,911

[1] 2013 revenues increased 29% to 10.9 million from $8.5 million over fiscal 2012. Revenues increased due to increased sales volumes. Production increased 25% to 120,634 boe for 2013 compared to production of 96,842 in 2012. Production increases were due primarily to results from the successful drilling programs in our Cherokee and Mississippi Projects and 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. Realized prices increased $2.97 to $90.71 per boe in 2013 versus $87.74 per boe for 2012.

[2] 2013 lease operating expenses increased 32% to $4.1 million from $3.1 million during 2012. However, lease operating expenses per boe increased only 5.9% to $33.95 in 2013 from $32.03 per boe in 2012. The 32% increase in lease operating expenses in 2013 was due primarily to increased expenses associated with increased Kansas production, and the new Colorado production added in 2013 that resulted from our acquisition of Black Raven Energy, Inc. on September 27, 2013 (see Note 5).

[3] 2013 depletion expense increased 9.7% to $1.7 million compared to $1.5 million for 2012. The depletion expense increase is due primarily to increased production levels as note in (2) above. Depletion expense per boe decreased $1.89 or 13.5% in 2013 compared to 2012.

[4] 2013 professional fees were $1.1 million, compared to $1.5 million during 2012. Professional fees decreased as a result of reduced legal fees, investment banking fees, consulting fees and engineering fees.

[5] Salaries and wages more than doubled in 2013 to $1.4 million compared to $0.6 million of salaries and wages expense incurred during 2012. The increase in salaries and wages was due primarily to the addition of employees to our Kansas and Texas staffs during 2013 and to the addition of Colorado employees on September 27, 2013 following the acquisition of Black Raven Energy, Inc. (see Note 5).

[6] Administrative expenses in 2013 were unchanged compared to 2012 at $0.8 million. Despite growth in production, employees and the addition of a new field office in 2013, administrative expenses were flat as a result of management's focus on controlling and reducing these expenses.

Reserves

Proved Reserves	**Year Ended December 31, 2013**	**Year Ended December 31, 2012**
Total proved PV10 (present value) of reserves	$ 102,411,800	$ 60,846,300
Total proved reserves (BOE)	5,804,600	2,927,000
Average Price (per bbl)	$ 87.89	$ 84.21
Average Price (per mcf)	$ 2.85	$ -

Of the 5.8 million BOE of total proved reserves, approximately 49% are classified as proved developed producing, approximately 17% are classified as proved developed non-producing, and approximately 34% are classified as proved undeveloped.

The following table presents summary information regarding our estimated net proved reserves as of December 31, 2013. 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, 2013.

Summary of Proved Oil and Gas Reserves
as of December 31, 2013

Proved Reserves Category	**Gross BOE**	**Net BOE**	**PV10 (before tax) [1]**
Proved, Developed	5,801,000	3,824,800	$ 74,234,300
Proved, Undeveloped	2,664,700	1,979,800	$ 28,717,500
Total Proved Reserves	8,465,700	5,804,600	$ 102,411,800

(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, 2013	**As of December 31, 2012**
PV10 (before tax)	$ 102,411,800	$ 61,206,000
Future income taxes, net of 10% discount	(20,964,145)	(12,333,000)
Standardized measure of discounted future net cash flows	$ 81,447,655	$ 48,873,000

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 and capital program in 2014.

The following table summarizes total current assets, total current liabilities and working capital at year ended December 31, 2013 compared to the year ended December 31, 2012.

	Year Ended December 31, 2013	Year Ended December 31, 2012	Difference
Current Assets	$ 5,401,304	$ 3,536,497	$ 1,864,807
Current Liabilities	$ 6,506,178	$ 4,556,476	$ (1,949,702)
Working Capital (deficit)	$ (1,104,874)	$ (1,019,979)	$ (84,895)

Senior Secured Credit Facility

On October 3, 2011, the Company and 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, the Company 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%.

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 35 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.

L. L. Bradford, 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.

The following table sets forth certain information regarding our current directors and executive officers. Our executive officers serve one-year terms.

Name	Age	Position	Board Committee(s)
Robert G. Watson, Jr.	37	President, Chief Executive Officer, and Director	None
Ryan A. Lowe	33	Director, Senior Vice President of Corporate Development	Audit
James G. Miller	65	Director	Audit, Compensation, Nominating
Richard E. Menchaca	45	Director	Audit, Compensation, Nominating
Lance W. Helfert	40	Director	Compensation, Nominating

Douglas M. Wright	61	Chief Financial Officer	None
David L. Kunovic	62	Executive Vice President, Exploration	None

Robert G. Watson, Jr. Mr. Watson has served as President, Chief Executive Officer, and Secretary since December 31, 2010. Prior to joining EnerJex, he co-founded Black Sable Energy, LLC, approximately 5 years ago and served as its Chief Executive Officer. During his tenure at Black Sable, Mr. Watson was responsible for the company's acquisition and development of two grassroots oil projects in South Texas, both of which were partnered with larger oil and gas companies on a promoted basis. Prior to founding Black Sable, he was a Senior Associate at American Capital, Ltd. (NASDAQ: ACAS), a publicly traded private equity firm and global asset manager with more than $100 billion of total assets under management. Mr. Watson began his career in the Energy Investment Banking Group at CIBC World Markets and subsequently founded and served as the Managing Partner of Centerra Energy Partners, LLC. Mr. Watson's experience in acquiring and developing oil projects, his knowledge of financial markets, and his managerial and leadership abilities that he has demonstrated while serving as the Company's President and Chief Executive Officer and as chief executive officer for Black Sable Energy, LLC, led to the board's conclusion that he should serve as a director.

Ryan A. Lowe. Mr. Lowe has served as Senior Vice President of Corporate Development since 2011 and as a Director since December 31, 2010. Mr. Lowe is the Chief Investment Officer of West Coast Asset Management, Inc., a registered investment advisor that has invested more than $200 million in the oil and gas industry on behalf of its principals and clients since 2000. He formerly served as a director and chairman of the audit committee for Black Raven Energy, Inc., before we acquired Black Raven in September 2013. Mr. Lowe is a CFA charterholder. His experience in business and finance and his experience as a director and chairman of the audit committee of a company in the oil and gas industry led to the board's conclusion that he should serve as a director.

James G. Miller. Mr. Miller has served as a Director since December 31, 2010. Mr. Miller retired in 2002 after serving as the Chief Executive Officer of Utilicorp United, Inc.'s business unit responsible for the company's electricity generation and electric and natural gas transmission and distribution businesses, which served 1.3 million customers in seven mid-continent states. Utilicorp traded on the New York Stock Exchange, and the company was renamed Aquila in 2002. In 2007, Utilicorp's electricity assets in northwest Missouri were acquired by Great Plains Energy Incorporated (NYSE: GXP) for $1.7 billion, and its natural gas properties and other assets were acquired by Black Hills Corporation (NYSE: BKH) for $940 million. Mr. Miller joined Utilicorp in 1989 through its acquisition of Michigan Gas Utilities, for which he served as the president from 1983 to 1991. Mr. Miller also is a member of the board of directors of Guardian 8 Holdings. He currently serves as Chairman of The Nature Conservancy, Missouri Chapter, for which he has been a Trustee for the past 12 years. Mr. Miller's experience as a chief executive officer and president, as well as his experience from serving as a board member, led to the board's conclusion that he should serve as a director.

Lance W. Helfert. Mr. Helfert has served as a Director since December 31, 2010. Mr. Helfert is the President and a co-founder of West Coast Asset Management, Inc. (WCAM), a registered investment advisor located in Montecito, California. Prior to co-founding WCAM, he managed a portfolio at Wilshire Associates and was involved in a full range of financial strategies at M.L. Stern & Co. Mr. Helfert is a co-author of *The Entrepreneurial Investor: The Art, Science and Business of Value Investing*, a book published by John Wiley & Sons. He has been featured in Kiplinger's Personal Finance, Forbes, Barron's, Fortune Magazine, and the Market Watch for his unique market prospective. In addition, Mr. Helfert has been a frequent guest commentator on CNBC and the Fox Business networks. Mr. Helfert has also served on the board of directors for Junior Achievement of Southern California and the Tri-Counties Make-A-Wish Foundation. Mr. Helfert's knowledge of the capital markets, coupled with his knowledge and understanding of finance and financial reporting led the board to conclude that he should serve as a director.

Richard E. Menchaca. Mr. Menchaca has been a Director since June 6, 2013. Mr. Menchaca attended the University of Texas at Arlington where he received a BBA in Finance and pursued a MBA in Finance, and received a Graduate Degree from the SMU Southwestern School of Banking. Mr. Menchaca spent 18 years in the corporate banking industry with First Republic Bank (n.k.a. Bank of America), Bank One in Fort Worth and Fuji Bank, and Guaranty Bank in Houston. While at Guaranty Bank, Mr. Menchaca was one of the founding members of the Oil and Gas Banking Group, and within 18 months of its formation became the most profitable lending group within the bank with over $900,000,000 of loans to oil and gas industry. Mr. Menchaca was the principal and founder of Petras Energy, LLC, an oil and gas production company based in Midland, Texas. The company was successfully sold in January 2006. Mr. Menchaca has been the founder and principal of several privately owned oil and gas companies with operations in Texas, Oklahoma and Louisiana. Since May 2010, Mr. Menchaca currently presides as President and Chief Executive Officer of Petroflow Energy Corporation, a Tulsa-based exploration and production company, as well as a member of its board of directors since June 2009. Mr. Menchaca also serves as a director on the board of Fortis Plastics and a non-profit organization based in Houston, Texas.

Douglas M. Wright. Mr. Wright has been Chief Financial Officer since August 2012. Mr. Wright served as Corporate Controller and Chief Accounting Officer of Nations Petroleum Company Ltd. from 2006 to August 2012. Prior to Nations, he served as a Manager of Financial Reporting for Noble Energy (contract). In 1996, he founded Fashion Investments Inc. and served as its Chief Executive Officer until 2005. Fashion Investments owned and operated the largest independent commercial laundry facility in Colorado Springs. From 1986 to 1996, Mr. Wright worked for Oryx Energy Company in various capacities including, Manager, Financial Reporting, Manager, Strategic Planning and General Auditor. From 1977 to 1986, he served as a Senior Manager with Deloitte & Touche. Mr. Wright is a Certified Public Accountant and earned his B.A. from the University of Pittsburgh and his MBA from the University of North Texas.

David L. Kunovic. Mr. Kunovic joined Black Raven Energy, Inc. on October 1, 2010 as Vice President of Exploration managing all phases of geologic and geophysical exploration and development activity for the company. Mr. Kunovic has over 34 years of experience as an exploration geologist, including 11 years as President of Kachina Energy, Inc., managing geologic and geophysical projects for several independent oil companies. He has also held positions as Vice President of Exploration for Canyon Energy, Inc. from 1994 – 2000 managing all exploration activities for the Rocky Mountain region; Petroleum Incorporated from 1991 – 1994 as Exploration Manager for all US exploration; Newport Exploration from 1984 – 1991 as Exploration Manager Rocky Mountain region; Apache Corporation from 1980 – 1984 as Senior Geologist working the Powder River and Denver Basins and Union Texas Petroleum from 1978-1980 as geologist — Rocky Mountain Basins. Mr. Kunovic holds a Bachelor's degree in Geology from the University of Colorado and also completed Masters level course work in Environmental Engineering and Groundwater at the University of Colorado.

Involvement in Certain Legal Proceedings

On December 23, 2013, the United States Securities and Exchange Commission (SEC) entered an order in an administrative proceeding, In the Matter of West Coast Asset Management, Inc., and Lance W. Helfert, File No. 3-15660. In that matter, WCAM and Mr. Helfert, without admitting or denying the allegations, entered into a settlement with the SEC regarding certain negligence-based violations of Section 17(a)(2) of the Securities Act and Sections 206(2) and 206(4) of the Investment Advisers Act of 1940 (the Advisers Act). The matter was based upon an untrue statement made in an email that Mr. Helfert sent, in 2008, to an adviser to a prospective investor in an investment fund that was managed by WCAM. The SEC ordered WCAM and Mr. Helfert to cease and desist from committing or causing further such negligence-based violations, censured them, ordered WCAM to disgorge certain fees, and ordered WCAM and Mr. Helfert each to pay a monetary fine. WCAM and Mr. Helfert timely paid those amounts to the SEC.

Except as set forth above, none of our executive officers or directors has been the subject of any Order, Judgment, or Decree of any Court of competent jurisdiction, or any regulatory agency permanently or temporarily enjoining, barring suspending or otherwise limiting him from acting as an investment advisor, underwriter, broker or dealer in the securities industry, or as an affiliated person, director or employee of an investment company, bank, savings and loan association, or insurance company or from engaging in or continuing any conduct or practice in connection with any such activity or in connection with the purchase or sale of any securities.

None of our executive officers or directors has been convicted in any criminal proceeding (excluding traffic violations) or is the subject of a criminal proceeding, which is currently pending.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), requires our executive officers and directors, and persons who beneficially own more than ten percent of our common stock, to file initial reports of ownership and reports of changes in ownership with the SEC. Executive officers, directors and greater than ten percent beneficial owners are required by SEC regulations to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that as of the date of this report they were all current in their 16(a) reports and that all reports were filed on a timely basis other than directors Ryan A. Lowe and Lance W. Helfert, who each filed a late form 4 on October 31 and November 5, 2013 respectively. Each late filing was with regard to one transaction.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all of our directors, officers and employees, as well as to directors, officers and employees of each subsidiary of the Company. Our Code of Ethics was filed as Exhibit 99.6 to the Annual Report on Form 10-KSB for the year ended March 31, 2007 which was filed on June 13, 2007. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. It is available on our website: enerjex.com, or you may contact Robert G. Watson at 210-451-5545 to request a copy of the Code or send your request to EnerJex Resources, Inc., Attn: Robert G. Watson, 4040 Broadway, Suite 508, San Antonio, Texas 78209. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code to any of our officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Audit Committee

Our Board of Directors has a standing audit committee.

Our Audit Committee consists of two independent directors, James G. Miller and Richard E. Menchaca and one non independent director, Ryan A. Lowe, each of whom has been selected for membership on the Audit Committee by the Board of Directors based on the board's determination that each is fully qualified, through a range of education, experiences in business and executive leadership and service on boards of directors, and an understanding of generally accepted accounting principles, to oversee our internal audit function, assess and select independent auditors, and oversee our financial reporting processes and overall risk management. The Audit Committee has the authority to seek advice and assistance from outside legal, accounting or other advisors and exercises such authority as it deems necessary. The full text of the charter of the Audit Committee can be found in the investor section of our website at *www.enerjex.com*.

The board has determined that James G. Miller and Richard E. Menchaca are financial experts as that term is used in Item 407(d)(5)(ii) of Regulation S-K promulgated under the Securities Exchange Act.

Although the Company is traded on OTCBB, the board of directors reviews the American Stock Exchange Company Guide listing standards on an annual basis. Mr. Miller and Mr. Menchaca qualify as independent directors as defined by Section 803 of the American Stock Exchange Company Guide and Section 10A (m) of the Securities Exchange Act of 1934, and Rule 10A-3 thereunder. In light of Mr. Lowe's relationship with West Coast Opportunity Fund, LLC, a significant shareholder, and his position as Senior Vice President of Corporate Development, our board of directors has determined that he is not independent (as independence is defined in Section 803 of the American Stock Exchange Company Guide).

The Audit Committee met four times during the fiscal year ended December 31, 2013.

ITEM 11. EXECUTIVE COMPENSATION.

The following table sets forth summary compensation information for the fiscal year ended December 31, 2013, and the year ended December 31, 2012, for our chief executive officer, chief financial officer and other highly compensated executive officers. We did not have any other executive officers as of the end of 2012 or 2013, whose total compensation exceeded $100,000. We refer to these persons as our named executive officers elsewhere in this report.

Summary Compensation Table

Name and Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)	All Other Compensation ($)	Total ($)
Robert G. Watson, Jr.	2013	$ 225,000	$ 35,000	$ -	$ 76,900	$ -	$ 336,900
President, Chief Executive Officer	2012	$ 150,000	$ -	$ -	$ 76,900	$ -	$ 226,900
Douglas M. Wright[1]	2013	$ 150,000	$ -	$ 132,000	$ 53,200	$ -	$ 335,200
Chief Financial Officer	2012	$ 140,000	$ -	$ 25,000	$ 17,700	$ -	$ 182,700
David L. Kunovic[2] Executive Vice President, Exploration	2013	$ 160,000	$ -	$ -	$ 23,700	$ -	$ 183,700
Ryan A. Lowe Senior Vice President of Corporate Development	2013	$ 80,000	$ 25,000	$ -	$ -	$ -	$ 105,000

(1) Douglas M. Wright was hired on August 15, 2012, and the compensation figures in the table above represent his annual compensation rates.

(2) David L. Kunovic was hired on September 27, 2013, and the compensation figures in the table above represent his annual compensation rates.

Outstanding Equity Awards at 2013 Fiscal Year-End

The following table lists the outstanding equity incentive awards held by our named executive officers as of the fiscal year ended December 31, 2013.

	Option Awards					
	Fiscal Year	Number of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date
Robert G. Watson, Jr.	2011	675,000	225,000	900,000	$ 0.40	12/31/2015
Douglas M. Wright	2012	375,000	375,000	750,000	$ 0.70	12/31/2022
David L. Kunovic	2013	-	750,000	750,000	$ 0.70	12/31/2023

Option Exercises for fiscal 2013

There were no options exercised by our named executive officers in 2013. See "Securities Authorized for Issuance under Equity Compensation Plans" for a description of our outstanding equity compensation plans.

Employment Agreements

Robert G. Watson, Jr. - Chief Executive Officer

On December 31, 2010, the Company and Robert G. Watson, Jr., entered into an Employment Agreement pursuant to which (i) we will employ Mr. Watson as its chief executive officer for a term ending on December 31, 2012, (ii) we will pay to Mr. Watson base compensation of $150,000 plus such discretionary cash bonus as our Board of Directors determines to be appropriate, (iii) we have granted to Mr. Watson an option for the purchase of 900,000 shares of common stock at $0.40 per share, (A) in which option he will vest in equal monthly increments over a period of 48 months, and in full upon a change of control of the company or the sale of all or substantially all of its assets, and (B) which option will have a term of five (5) years, and (iv) if we terminate Mr. Watson's employment without "Cause" (as defined in the Employment Agreement), then we will pay to Mr. Watson as severance pay (A) the Base Compensation that would have accrued during the remainder of the term of that Employment Agreement, and (B) if that termination occurs after 16 months of employment, we also will pay to Mr. Watson additional severance pay in the amount of $100,000.

On December 31, 2012, the Company entered into an amended and restated employment agreement with Robert G. Watson, Jr. as Chief Executive Officer of the Company for a two-year period commencing December 31, 2012. The employment agreement provides for an annual base salary of $225,000 per year.

Douglas M. Wright - Chief Financial Officer

On August 15, 2012, the Company and Douglas M. Wright, entered into an Employment Agreement pursuant to which (i) we will employ Mr. Wright as our chief financial officer for a term ending on December 31, 2013, (ii) we will pay to Mr. Wright base compensation of $140,000 plus such discretionary cash bonus as our chief executive officer determines to be appropriate, and (iii) if we terminate Mr. Wright's employment without "Cause" (as defined in the Employment Agreement), then we will pay to Mr. Wright $32,500 as severance pay after six (6) months of employment.

Potential Payments Upon Termination or Change in Control

We entered into employment agreements with our chief executive officer and chief financial officer, which could result in payments to such officers because of their resignation, incapacity or disability, or other termination of employment with us or our subsidiaries, or a change in control, or a change in their responsibilities following a change in control.

Director Compensation

The following table sets forth summary compensation information for the fiscal year ended December 31, 2013 for each of our non-employee directors.

Name	Fees Earned or Paid in Cash $	Stock Awards $	Option Awards (2) $	All Other Compensation $	Total $
James G. Miller	$ 25,000	$ -	$ -	$ -	$ 25,000
Lance W. Helfert	$ -	$ -	$ -	$ -	$ -
Richard E. Menchaca	$ 25,000	$ -	$ -	$ -	$ 25,000

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

The following table presents information, to the best of our knowledge, about the ownership of our common stock on December 31, 2013 relating to those persons known to beneficially own more than 5% of our capital stock and by our directors and executive officers. The percentage of beneficial ownership for the following table is based on 109,254,045 shares of outstanding common stock.

Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and does not necessarily indicate beneficial ownership for any other purpose. Under these rules, beneficial ownership includes those shares of common stock over which the stockholder has sole or shared voting or investment power. It also includes shares of common stock that the stockholder has a right to acquire within 60 days after December 31, 2013 pursuant to options, warrants, conversion privileges or other right. The percentage ownership of the outstanding common stock, however, is based on the assumption, expressly required by the rules of the Securities and Exchange Commission, that only the person or entity whose ownership is being reported has converted options or warrants into shares of EnerJex's common stock.

Name and Address of Beneficial Owner (1)	Number of Shares	Percent of Outstanding Shares of Common Stock (2)
Robert G. Watson, Jr., CEO/President and Director (3)	4,712,500	4.4 %
Ryan A. Lowe, Director (4)(5)(7)	128,585	0.1 %
Lance W. Helfert, Director (4)(5)(6)	201,999	0.2 %
James G. Miller, Director	2,173,871	2.0 %
West Coast Opportunity Fund LLC (4) 1205 Coast Village Road Montecito, CA 93108	52,817,871	48.3 %
Montecito Venture Partners, LLC (5) 1205 Coast Village Road Montecito, California 93108	6,593,972	6.0 %
Orfalea Family Revocable Trust	9,013,459	8.3 %
Newman Family Trust	5,500,000	5.0 %
Douglas M. Wright, CFO	675,000	0.6 %
Directors, Officers and Beneficial Owners as a Group		74.9 %8

(1) As used in this table, "beneficial ownership" means the sole or shared power to vote, or to direct the voting of, security, or the sole or shared investment power with respect to a security (i.e., the power to dispose of, or to direct the disposition of, a security). The address of each person is care of the Registrant, 4040 Broadway, Suite 508, San Antonio, Texas 78209.

(2) Figures are rounded to the nearest tenth of a percent.

(3) Includes 4,000,000 shares held by RGW Energy, LLC, of which Mr. Watson is the sole member, and 712,500 shares under an option granted to Mr. Watson to purchase 900,000 shares of common stock at $0.40 per share. Mr. Watson vests in that option in equal monthly increments over 48 months commencing January 1, 2011.

(4) West Coast Asset Management, Inc. (the "Managing Member") is the Managing Member of West Coast Opportunity Fund, LLC, which directly owns all of the shares listed opposite its name in the table above. Lance W. Helfert and Ryan A. Lowe serve on the investment committee of the Managing Member. Each Reporting Person disclaims beneficial ownership of all securities reported herein, except to the extent of their pecuniary interest therein, if any, and this report shall not be deemed an admission that such Reporting Person is the beneficial owner of the shares for purposes of Section 16 of the Securities and Exchange Act of 1934 or for any other purposes.

(5) Montecito Venture Partners, LLC is a controlled affiliate of West Coast Asset Management, Inc. Includes 2,417,660 shares of Series A Preferred Stock that is convertible into 2,417,660 shares of the Registrant's common stock. Ryan A. Lowe and Lance W. Helfert are the Managers of Montecito Venture Partners, LLC, which directly owns all of the shares listed opposite its name in the table above. Each Reporting Person disclaims beneficial ownership of all securities reported herein, except to the extent of their pecuniary interest therein, if any, and this report shall not be deemed an admission that such Reporting Person is the beneficial owner of the shares for purposes of Section 16 of the Securities and Exchange Act of 1934 or for any other purposes.

(6) Excludes 287,145 of the shares beneficially owned by Mr. Helfert by reason of his ownership interest in West Coast Opportunity Fund, LLC, and 5,914,177 of the shares beneficially owned by Mr. Helfert by reason of his ownership interest in Montecito Venture Partners, LLC.

(7) Excludes 58,754 of the shares beneficially owned by Mr. Lowe by reason of his ownership interest in West Coast Opportunity Fund, LLC, and 966,940 of the shares beneficially owned by Mr. Lowe by reason of his ownership interest in Montecito Venture Partners, LLC.

Equity Compensation Plan Information

Our board of directors approved the 2000/2001 Stock Option Plan and our stockholders ratified the plan on September 25, 2000. The total number of options that could be granted under the plan was 200,000 shares.

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 400,000 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 1,000,000. 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 from 1,000,000 to 1,250,000, and (iii) add restricted stock as an eligible award that can be granted under the Stock Incentive Plan.

On June 6, 2013, stockholders approved the adoption of the 2013 Stock Incentive Plan, reserving 5,000,000 shares of common stock under the plan.

General Terms of Plans

Officers (including officers who are members of the board of directors), directors, and other employees and consultants and our subsidiaries (if established) will be eligible to receive awards under the 2000/2001 Stock Option Plan and the Stock Incentive Plan. A committee of the board of directors will administer the plans and will determine those persons to whom awards will be granted, the number of and type of awards to be granted, the provisions applicable to each grant and the time periods during which the awards may be exercised. No awards may be granted more than ten years after the date of the adoption of the plans.

Non-qualified stock options will be granted by the committee with an option price equal to the fair market value of the shares of common stock to which the non-qualified stock option relates on the date of grant. The committee may, in its discretion, determine to price the non-qualified option at a different price. In no event may the option price with respect to an incentive stock option granted under the plans be less than the fair market value of such common stock to which the incentive stock option relates on the date the incentive stock option is granted. However the price of an incentive stock option will not be less than 110% of the fair market value per share on the date of the grant in the case of an individual then owning more than 10% of the total combined voting power of all classes of stock of the corporation.

Each option granted under the 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.

Restricted stock will have full dividend, voting and other ownership rights, unless otherwise indicated in the applicable award agreement pursuant to which it is granted. If any dividends or distributions are paid in shares of common stock during the restricted period, the applicable award agreement may provide that such shares will be subject to the same restrictions as the restricted stock with respect to which they were paid.

These plans are intended to encourage directors, officers, employees and consultants to acquire ownership of common stock. The opportunity so provided is intended to foster in participants a strong incentive to put forth maximum effort for our continued success and growth, to aid in retaining individuals who put forth such effort, and to assist in attracting the best available individuals in the future.

The following table sets forth information as of fiscal year ended December 31, 2013 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	3,467,000	$ 0.62	1,733,000

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

We describe below transactions and series of similar transactions that have occurred during this fiscal year ended December 31, 2013 to which we were a party or will be a party in which:

- The amounts involved exceeds the lesser of $120,000 or one percent of the average of our total assets at year end for the last two completed fiscal years ($535,000); and
- A director, executive officer, holder of more than 5% of our common stock or any member of their immediate family had or will have a direct or indirect material interest.

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. 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. ("Black Raven"), 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. Pursuant to the Merger Agreement, and 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 common shares for 41,327,516 common shares of EnerJex.

Director Independence

Our Board of Directors has affirmatively determined that Mr. Miller and Mr. Menchaca are independent directors, as defined by Section 803 of the American Stock Exchange Company Guide.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

L.L. Bradford served as our independent public accountants for the year ended December 31, 2013 and Weaver Martin & Samyn LLC served as our independent public accountant for the year ended December 31, 2012. Aggregate fees billed to us for the years ended December 31, 2013 and 2012 were as follows:

	Year Ended December 31, 2013	Year Ended December 31, 2012
Audit Fees (1)	$ 73,000	$ 80,430
Audit-Related Fees (2)	$ -	$ -
Tax fees (3)	$ 20,811	$ 15,785
All Other Fees (4)	$ -	$ -
Total fees of our principal accountant	$ 93,811	$ 96,215

(1) Audit Fees include fees billed and expected to be billed for services performed to comply with Generally Accepted Auditing Standards (GAAS), including the recurring audit of the Company's consolidated financial statements for such period included in this Annual Report on Form 10-K and for the reviews of the consolidated quarterly financial statements included in the Quarterly Reports on Form 10-QSB filed with the Securities and Exchange Commission. This category also includes fees for audits provided in connection with statutory filings or procedures related to audit of income tax provisions and related reserves, consents and assistance with and review of documents filed with the SEC. For the year ended December 1, 2013, audit fees of $45,500 were paid to Weaver Martin & Samyn and $27,500 were paid to L.L.Bradford.

(2) Audit-Related Fees include fees for services associated with assurance and reasonably related to the performance of the audit or review of the Company's financial statements. This category includes fees related to assistance in financial due diligence related to mergers and acquisitions, consultations regarding Generally Accepted Accounting Principles, reviews and evaluations of the impact of new regulatory pronouncements, general assistance with implementation of Sarbanes-Oxley Act of 2002 requirements and audit services not required by statute or regulation.

(3) Tax fees consist of fees related to the preparation and review of the Company's federal and state income tax returns.

(4) Other fees

Audit Committee Policies and Procedures

Our Audit Committee pre-approves 100% of the services to be provided to us by our independent auditor. This process involves obtaining (i) a written description of the proposed services, (ii) the confirmation of our Principal Accounting Officer that the services are compatible with maintaining specific principles relating to independence, and (iii) confirmation from our securities counsel that the services are not among those that our independent auditors have been prohibited from performing under SEC rules, as outlined in the Audit Committee charter. The members of the Audit Committee then make a determination to approve or disapprove the engagement of L.L. Bradford for the proposed services. In fiscal 2013, all fees paid to L.L Bradford were unanimously pre-approved in accordance with this policy.

Less than 50 percent of hours expended on the principal accountant’s engagement to audit the registrant’s financial statements for the most recent fiscal year were attributed to work performed by persons other than the principal accountant’s full-time, permanent employees.

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
1.1	Form of Underwriting Agreement (Previously filed)

2.1	Agreement and Plan of Merger between Millennium Plastics Corporation and Midwest Energy, Inc. effective August 15, 2006 (incorporated by reference to Exhibit 2.3 to the Form 8-K 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 Exhibit 3.3 to the Form SB-2 filed on February 23, 2001)
3.3	Certificate of Amendment of Articles of Incorporation (Previously filed)
4.1	Article VI of Amended and Restated Articles of Incorporation of Millennium Plastics Corporation (incorporated by reference to Exhibit 1.3 to the Form 8-K filed on December 6, 1999)
4.2	Article II and Article VIII, Sections 3 & 6 of Amended and Restated Bylaws of Millennium Plastics Corporation (incorporated by reference to Exhibit 4.1 to the Form SB-2 filed on February 23, 2001)
4.3	Specimen common stock certificate (incorporated by reference to Exhibit 4.3 to the Form S-1/A filed on May 27, 2008)
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).
10.1	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)
10.2	Form of Officer and Director Indemnification Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on October 16, 2008)
10.3	Euramerica Letter Agreement Amendment dated September 15, 2008 (incorporated by reference to Exhibit 10.10 to the Form 8-K filed on September 18, 2008)
10.4	Euramerica Letter Agreement Amendment dated October 15, 2008 (incorporated by reference to Exhibit 10.11 to the Form 8-K filed on October 21, 2008)
10.5	Joint Operating Agreement with Pharyn Resources to explore and develop the Brownrigg Lease Press Release dated June 1, 2009 (incorporated by reference to Exhibit 99.1 to the Form 8-K filed on June 5, 2009).
10.6	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)
10.7	Standby Equity Distribution Agreement with Paladin Capital Management, S.A. dated December 3, 2009 (incorporated by reference to Exhibit 10.52 to the Form S-1 filed on December 9, 2009)
10.8	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)
10.9	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)
10.10	Securities Purchase and Asset Acquisition Agreement between EnerJex Resources, Inc. and West Coast Opportunity Fund, LLC; Montecito Venture Partners, LLC; J&J Operating Company, LLC and Frey Living Trust dated December 31, 2010 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on January 6, 2011).
10.11	Stock Repurchase Agreement between EnerJex Resources, Inc. and Working Interest Holdings, LLC dated December 31, 2010 (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on January 6, 2011).
10.12	Securities Purchase Agreement between EnerJex Resources, Inc. and various Investors dated December 31, 2010 (incorporated by reference to Exhibit 10.3 to the Form 8-K filed on January 6, 2011).
10.13	Employment Agreement between EnerJex Resources, Inc. and Robert G. Watson dated December 31, 2010 (incorporated by reference to Exhibit 10.4 to the Form 8-K filed on January 6, 2011).
10.14	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).
10.15	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).
10.16	Third Amendment to Credit Agreement dated September 29, 2010 (incorporated by reference to Exhibit 10.33 to the Transition Report on Form 10-K filed on April 21, 2011).
10.17	Fourth Amendment to Credit Agreement dated December 31, 2010 (incorporated by reference to Exhibit 10.34 to the Transition Report on Form 10-K filed on April 21, 2011).
10.18	Letter Agreement with Registrant, James Loeffelbein, John Loeffelbein and J&J Operating dated January 14, 2011 (incorporated by reference to Exhibit 10.1 on Form 8-K filed on January 18, 2011).

10.19	Form of Securities Purchase Agreement among Registrant and Investors dated March 31, 2011 (incorporated by reference to Exhibit 10.1 on Form 8-K filed on April 4, 2011).
10.20	Form of Warrant among Registrant and Investors dated March 31, 2011 (incorporated by reference to Exhibit 10.2 on Form 8-K filed on April 4, 2011).
10.21	Form of Stock Redemption Agreement among Registrant and Working Interest Holdings, LLCs dated March 31, 2011 (incorporated by reference to Exhibit 10.1 on Form 8-K filed on April 4, 2011).
10.22	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).
10.23	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).
10.24	Rantoul Partners General Partnership Agreement dated December 14, 2011 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on December 14, 2011).
10.25	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).
10.26	First Amendment to General Partnership Agreement for Rantoul Partners dated March 30, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on April 5, 2012).
10.27	Share Option Agreement by and among the EnerJex and Enutroff dated August 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on October 10, 2012).
10.28	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).
10.29	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).
10.30	Securities and Asset Purchase Agreement by and among Registrant and James Loeffelbein and Enutroff dated November 3, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on January 7, 2013).
10.31	Second Amendment to General Partnership Agreement of Rantoul Partners dated November 27, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on November 29, 2012).
10.32	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).
10.33	Partial Assignment of Assets by and among Rantoul Partners and Working Interest, LLC, dated December 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on January 30, 2013).
10.34	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).
10.35	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).
10.36	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).
10.37	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).
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

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 28, 2014

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. Robert G. Watson, Jr.	President, Chief Executive Officer, (Principal Executive Officer), Secretary and Director	March 28, 2014
/s/ Douglas M. Wright Douglas M. Wright	Chief Financial Officer (Principal Financial Officer)	March 28, 2014
/s/ Ryan A. Lowe Ryan A. Lowe	Director and Senior Vice President of Corporate Marketing	March 28, 2014
/s/ Lance W. Helfert Lance Helfert	Director	March 28, 2014
/s/ James G. Miller James G. Miller	Director	March 28, 2014
/s/ Richard E. Menchaca Richard E. Menchaca	Director	March 28, 2014

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 sheets of EnerJex Resources, Inc. and Subsidiaries as of December 31, 2012, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years 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 audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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 audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EnerJex Resources, Inc. and Subsidiaries as of December 31, 2012 and the results of its consolidated operations, stockholders' equity, and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Weaver, Martin & Samyn

Weaver, Martin & Samyn, LLC

Kansas City, Missouri

April 10, 2013

EnerJex Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2013	December 31, 2012
Assets		
Current Assets:		
Cash	$ 1,079,356	$ 767,494
Restricted Cash	228,840	-
Accounts receivable	2,461,746	1,221,962
Inventory	238,794	-
Marketable securities	1,018,573	1,018,573
Deposits and prepaid expenses	373,994	528,468
Total current assets	5,401,303	3,536,497
Non-current assets:		
Fixed assets, net of accumulated depreciation of $1,785,401	2,406,591	309,877
Oil & gas properties using full cost accounting, net of accumulated DD&A	61,349,403	33,202,898
Other non-current assets	834,180	-
Total non-current assets	64,590,174	33,512,775
Total assets	$ 69,991,477	$ 37,049,272
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 2,424,009	$ 2,384,090
Accrued liabilities	3,070,461	590,205
Derivative liability	1,011,708	757,181
Note Payable	-	825,000
Total current liabilities	6,506,178	4,556,476
Non-Current Liabilities		
Asset retirement obligation	2,687,801	1,336,151
Derivative liability	339,642	1,043,114
Long-term debt	31,547,255	8,500,000
Total non-current liabilities	34,574,698	10,879,265
Total liabilities	41,080,876	15,435,741
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $0.001 par value, 25,000,000 shares authorized, 4,779,460 shares issued and outstanding	4,780	4,780
Common stock, $0.001 par value, 250,000,000 shares authorized; shares issued and outstanding - 115,004,045 at December 31, 2013 and 73,586,529 at December 31, 2012	115,005	73,587
Treasury stock, 5,570,000 shares at December 31, 2013 and at December 31,2012	(2,551,000)	(2,551,000)
Accumulated other comprehensive income	(552,589)	(552,589)
Paid in capital	52,356,811	45,352,096
Retained (deficit)	(20,462,406)	(20,713,343)
Total stockholders' equity	28,910,601	21,613,531
Total liabilities and stockholders' equity	$ 69,991,477	$ 37,049,272

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31, 2013	2012
Oil & gas revenues	$ 10,942,270	$ 8,496,519
Expenses:		
Direct operating costs	4,095,850	3,102,321
Depreciation, depletion and amortization	1,856,660	1,633,467
Professional fees	1,071,740	1,483,720
Salaries	1,432,081	601,533
Administrative expense	798,457	808,836
Total expenses	9,254,788	7,629,877
Income from operations	1,687,482	866,642
Other income (expense):		
Interest expense	(772,471)	(302,357)
Gain (loss) on derivatives	(740,456)	55,708
Other income	1,115,898	121,127
Total other income (expense)	(397,029)	(125,522)
Income before provision for income taxes	1,290,453	741,120
Provision for income taxes	-	-
Net income	$ 1,290,453	$ 741,120
Net income attributed to EnerJex Resources Inc.	$ 1,290,453	$ 345,992
Net income attributed to non-controlling interest in subsidiary	-	395,128
Net income	$ 1,290,453	$ 741,120
Net income attributed to EnerJex Resources Inc.	1,290,453	345,992
Preferred dividends	(1,039,516)	(608,459)
Net income (loss) attributed to EnerJex Resources Inc. common stockholders	250,937	(262,467)
Net Income (loss) per share- basic and diluted	$ 0.00	$ 0.00
Weighted average shares outstanding	78,229,050	69,714,758

See Notes to Consolidated Financial Statements.

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

	Preferred Stock		Common Stock		Treasury	Accumulated Other Comprehensive	Paid In	Retained	Total Stockholders' Equity EnerJex Resources	Non Controlling Interest	Total Stockholders'
	Shares	Amount	Shares	Amount	Stock	Income	Capital	Deficit	Inc.	Subsidiary	Equity
Balance, January 1, 2012	4,779,460	$ 4,780	73,411,529	$ 73,412	$ (1,500,000)	$ (552,589)	$ 43,556,486	$ (20,450,876)	$ 21,131,213	$ 565,728	$ 21,696,941
Stock Issued for Services	-	-	175,000	175	-	-	122,226	-	122,401	-	122,401
Acquisition of Treasury Stock	-	-	-	-	(1,051,000)	-	-	-	(1,051,000)	-	(1,051,000)
Issuance of Stock Options							167,033	-	167,033	-	167,033
Warrants Issued for Services							85,892	-	85,892	-	85,892
Sale of Non-Controlling Interest by Subsidiary	-	-	-	-	-	-	-	-	-	2,650,000	2,650,000
Accretion to EnerJex Due to Sale of Non-Controlling Interest by Subsidiary	-	-	-	-	-	-	1,420,459	-	1,420,459	(1,420,459)	-
Liquidation of Non-Controlling Interests										(592,936)	(592,936)
Liquidation of Non-Controlling Interests										(1,597,461)	(1,597,461)
Dividends Paid on Preferred Stock	-	-	-	-	-	-	-	(608,459)	(608,459)	-	(608,459)
Net Income for the Year	-	-	-	-	-	-	-	345,992	345,992	395,128	741,120
Balance, December 31, 2012	4,779,460	4,780	73,586,529	73,587	(2,551,000)	(552,589)	45,352,096	(20,713,343)	21,613,531	-	21,613,531
Stock Issued for Services	-	-	90,000	90	-	-	44,910	-	45,000	-	45,000
Issuance of Stock Options	-	-	-	-	-	-	72,434	-	72,434	-	72,434
Warrants Issued for Services	-	-	-	-	-	-	40,790	-	40,790	-	40,790
Stock Issued for shares of Black Raven Energy, Inc.			41,327,516	41,328			6,846,581	-	6,887,909	-	6,887,909
Dividends Paid on Preferred Stock	-	-	-	-	-	-	-	(1,039,516)	(1,039,516)	-	(1,039,516)
Net Income for the Year	-	-	-	-	-	-	-	1,290,453	1,290,453	-	1,290,453
Balance, December 31, 2013	4,779,460	$ 4,780	115,004,045	$ 115,005	$ (2,551,000)	$ (552,589)	$ 52,356,811	$ (20,462,406)	$ 28,910,601	$ -	$ 28,910,601

<u>See Notes to Consolidated Financial Statements.</u>

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

	Year Ended December 31, 2013	2012
Cash flows from operating activities		
Net Income	$ 1,290,453	$ 741,120
Depreciation, depletion and amortization	1,856,660	1,633,467
Stock, options and warrants issued for services	255,977	285,230
Accretion of asset retirement obligation	139,779	93,973
Settlement of asset retirement obligations	(36,758)	-
(Gain) on derivatives	(448,945)	(927,039)
Loss (Gain) on sale of fixed assets	5,833	(1,378)
Adjustments to reconcile net income to cash from operating activities:		
Accounts receivable	(361,314)	232,443
Inventory	34,336	-
Deposits and prepaid expenses	235,471	(93,123)
Accounts payable	(545,112)	28,398
Accrued liabilities	686,441	291,652
Cash flows from operating activities	3,112,821	2,284,743
Cash flows from investing activities		
Purchase of Treasury Stock	-	(226,000)
Purchase of fixed assets	(184,794)	(115,274)
Additions to oil and gas properties	(7,672,492)	(10,247,539)
Sale of oil and gas properties	454,975	-
Settlements of asset retirement obligations	(18,910)	-
Proceeds from sale of vehicles	12,755	11,240
Net cash acquired from Black Raven	656,693	-
Cash flows from investing activities	(6,751,773)	(10,577,573)
Cash flows from financing activities		
Sale of non-controlling interest in subsidiary	-	2,650,000
Dividend paid	(757,992)	(433,696)
Borrowings on long-term debt	6,000,000	4,700,000
Distribution to non-controlling interest in subsidiary	-	(592,936)
Payments on long-term debt	(9,096)	(33,484)
Payments on notes payable	(825,000)	-
Deferred financing costs	(228,258)	-
Cash flows from financing activities	4,179,654	6,289,884
Increase (decrease) in cash and cash equivalents	540,702	(2,002,946)
Cash and cash equivalents, beginning	767,494	2,770,440
Cash and cash equivalents, end	$ 1,308,196	$ 767,494
Supplemental disclosures:		
Interest paid	$ 375,932	$ 195,125
Income taxes paid	$ -	$ -
Non-cash transactions:		
Share-based payments issued for services	$ 216,810	$ 452,263
Treasury stock purchased with a note payable	$ -	$ 825,000
Preferred dividends payable	$ 456,289	$ 174,763

See 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 and our majority owned subsidiary Rantoul Partners (through December 31, 2012).

Rantoul Partners was formed in 2011 by our contribution of certain oil assets totaling $2,282,918 to the partnership for 100% ownership in the entity. The assets were valued at their historic cost which approximated market. In 2011 Rantoul Partners sold 11.75% of the partnership to 2 investors for $2,350,000. 11.75% of the book value of Rantoul Partners after the investment by non-controlling entities was $544,368. The difference between the investment amount ($2,350,000) and the book value bought ($544,368) is accretive to EnerJex in the amount of $1,805,632. This amount was recorded as EnerJex paid in capital. In 2012 an additional $2,650,000 was invested by the two non-controlling owners for an additional 13.25% ownership (bringing their total to 25%). 13.25% of the book value of Rantoul Partners after the additional investments by the non-controlling entities was $1,229,541. The difference between the investment amount ($2,650,000) and the book value bought ($1,229,541) is accretive to EnerJex in the amount of $1,420,459. This amount was recorded as paid in capital.

On December 31, 2012 Rantoul Partners was liquidated. At the time of liquidation we owned 75% of Rantoul Partners and 75% of the working interest of Rantoul Partners. We received 75% of the net assets less liabilities of Rantoul Partners that totaled approximately $4,792,380 and a 75% working interest in the oil properties of Rantoul Partners. The non-controlling owners of Rantoul Partners received 25% of the assets less liabilities ($1,597,461) and 25% of the working interest in the properties of Rantoul Partners.

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. The results of operations of Black Raven are not included in the consolidated statements of operations at December 31, 2012 or for the year then ended.

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 a 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, 2013 and 2012. 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, 2013. 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, 2013 are the years ended December 31, 2010, 2011, 2012 and 2013. Tax years ending prior to 2010 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.

Property and Equipment

Property and equipment are recorded at cost. 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, 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.

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, 2013, and 2012 we sold our produced crude oil to Coffeyville Resources, Plains Marketing, L.P., and Sunoco, Inc. on a month-to-month basis. For the year ended December 31, 2013, 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, 2013 and 2012.

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, 2013, diluted net income per share did not include the effect of 2,592,500 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, 2012, diluted net income per share did not include the effect of 192,970 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 - Stock Transactions

The Series A preferred stock is convertible into 4,779,460 shares of our common stock, and the Series A preferred stock, by its terms, shall convert into common stock on a one-to-one basis (subject to adjustment) once the cumulative dividends paid with regard to such stock equal to original principal value of $1.00 per share. In the event of liquidation, the holders of our Series A preferred stock would receive priority liquidation payments before payments to common shareholders equal to the amount of the stated value of the preferred stock before any distributions would be made to our common shareholders. The preferred stockholders have the right, by majority vote of the shares of preferred stock, to generally approve any issuances by us of equity that is senior to or equal in rights to the preferred stock.

We are required by the terms of our Series A preferred stock to declare dividends each calendar quarter in an aggregate amount equal to one-third of our adjusted net cash from operating activities reduced by any principal amount of debt repayment in such calendar quarter to institutional lenders and other secured creditors. Dividends of $583,227 and $433,696 were paid for the years ended December 31, 2013 and 2012 respectively. A dividend of $456,289 will be paid in the second quarter of 2014 to preferred shareholders of record as of December 31, 2013.

Stock transactions in fiscal year ended December 31, 2013

We issued 90,000 shares at $0.50 per share to two employees as compensation. The market value of the stock at the date of issuance was $0.55 per share.

On September 30, 2013 the Company issued 41,327,516 shares to Black Raven Energy, Inc. shareholders in exchange for their shares of Black Raven Energy, Inc. common shares. (See Note 5).

Stock transactions in fiscal year ended December 31, 2012

We issued 60,000 shares at $0.77 per share to an Investor Relations firm in exchange for services. The market value of the stock at the date of issuance was $0.77 per share. We also issued 75,000 shares to a Director of the Company for services and 40,000 shares to an employee of the Company. The market price at the date of issuance for these shares was $0.60 and $0.78 respectively.

On November 30, 2012 the Company purchased two million shares of stock from a shareholder of the Company for $323,035 in cash (including an option payment that we previously made to the selling stockholder) and a note payable of $825,000 bearing interest at a rate per annum of twenty-four hundredths percent (0.24%) (See Note 13).

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.

2000-2001 Stock Option Plan

The Board of Directors approved a stock option plan and our stockholders ratified the plan on September 25, 2000. The total number of options that can be granted under the plan is 200,000 shares.

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 400,000 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 1,000,000. 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 from 1,000,000 to 1,250,000, and (iii) add restricted stock as an eligible award that can be granted under the Stock Incentive Plan.

On December 31, 2010 we granted 900,000 options that vest ratably over a 48 month period and are exercisable at $0.40 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 the years ended December 31, 2012 and 2011 was $76,938 respectively and the amount of expense to be recognized in future periods is $153,876. There are 675,000 and 450,000 options vested at December 31, 2013 and December 31, 2012 respectively.

On December 1, 2012 we granted 785,000 options to four employees of the Company, 33% of which vest after one year. The remaining options vest monthly over a two year period. The fair value of the options on the date of the grant was calculated using the Black-Scholes model was $167,032 using the following weighted average assumptions: exercise price of $0.70 per share; common stock price of $0.56 per share; volatility of 67%; term of three years; dividend yield of 0%; interest rate of .47%. The amount recognized as expense in the year ended December 31, 2012 was $18,825 and the amount of expense to be recognized in future periods is $148,208. At December 31, 2013 approximately 350,000 options were vested. None of the options were vested at December 31, 2012.

On June 6, 2013, stockholders approved the adoption of the 2013 Stock Incentive Plan, reserving 5,000,000 shares of common stock under the plan. Neither the 2000/2001 Stock Option Plan nor the Stock Incentive Plan had sufficient shares to cover options that we intend to grant and those plans are dated and would not allow us to grant tax-qualified incentive stock options. The 2013 Stock Incentive Plan reserves 5,000,000 shares of our common stock for the granting of options and issuance of restricted shares to our employees, officers, directors, and consultants.

In 2013, we granted 1,787,000 options to thirteen employees. These options were issued throughout the year. 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 was calculated using the Black-Scholes model was $376,103 using the following weighted average assumptions: exercise price of $0.70 per share; common stock price of ranging from $0.53 to $0.56 per share; volatility ranging from 67% to 72%; term of three years; dividend yield of 0%; interest rate of .47%. The amount recognized as expense in the year ended December 31, 2013 was $33,267 and the amount of expense to be recognized in future periods is $342,836. None of these options were vested at December 31, 2013.

Warrant Transactions

On March 31, 2011, we granted 2,838,330 Warrants to each investor that entered into the Securities Purchase Agreement for additional consideration, each investor received a stock purchase warrant to purchase 1 share of common stock at a price of $0.90 per share, for each 2 shares of common stock purchased.

Each Warrant was exercisable until December 31, 2011. The fair value at the date of the grant was calculated using the Black-Scholes model and totaled $74,164, using the following weighted average assumptions: exercise price of $0.90 per share; common stock price of $0.85 per share; volatility of 42%; term of nine months; dividend yield of 0%; interest rate of 0.30%. On December 31, 2011 the warrants were extended for an additional nine months to expire September 30, 2012. The fair value at the date of the extension was calculated using the Black-Scholes model and totaled $154,676, using the following weighted average assumptions: exercise price of $0.90 per share; common stock price of $0.90 per share; volatility of 71%; term of nine months; dividend yield of 0%; interest rate of 0.25%. The amount recognized as expense in the year ended December 31, 2011 was based on an estimate of the number of warrants that would be exercised and totaled $228,840. On September 30, 2012 the warrants were cancelled unexercised.

On May 31, 2012, we granted 250,000 Warrants to an investor relations firm for investor relations services to be performed over the next two years. Each warrant is 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 using the following assumptions. The exercise price is $0.70 per share. The market price of our stock at the grant date was $0.75 per share. We assumed volatility of 82%, a dividend yield of 0.0%, an interest rate of 0.30% and a two year term. On January 3, 2013, we granted 300,000 Warrants to an investor relations firm for investor relations 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 using the following assumptions. The exercise price is $0.70 per share. The market price of our stock at the grant date was $0.50 per share. We assumed volatility of 77%, a dividend yield of 0.0%, an interest rate of 0.27% and a two year term. In the fourth quarter of 2013 all 550,000 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, 2012	900,000	$ 0.40	2,838,330	$ 0.90
Granted	785,000	0.70	250,000	0.70
Cancelled	-	-	(2,838,330)	(0.90)
Exercised	-	-	-	-
Outstanding December 31, 2012	1,685,000	$ 0.54	250,000	$ 0.70
Granted	1,787,000	0.70	300,000	0.70
Cancelled	(5,000)	(0.70)	(550,000)	(0.70)
Exercised	-	-	-	-
Outstanding December 31, 2013	3,467,000	$ 0.62	-	$ -

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, 2012	$ 908,790
Liabilities incurred during the period	347,018
Liabilities settled during the period	(1,427)
Accretion	81,770
Asset retirement obligations, December 31, 2012	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

Note 4 - Long-Term Debt

Senior Secured Credit Facility

On October 3, 2011, the Company and 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 the 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%.

Our Current borrowing base is $38 million, of which we had borrowed $31.5 million as of December 31, 2013. We intend to conduct an additional borrowing base review in the second quarter of 2014 and we expect increases in production and the maturity of existing production to result in an additional borrowing base increase as part of the additional borrowing base review. For the year ended December 31, 2013 the interest rate was 3.3%. This facility expires on October 3, 2015.

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, 2013 was $47,255.

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 periods ended December 31, 2013 and 2012 with the financial information of Black Raven for the twelve months ended December 31, 2013 2012.

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, 2012. 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	2012
Revenues	$ 14,362,000	$ 15,483,000
Income from operations	$ 2,106,000	$ 2,967,200
Net income (loss)	$ (141,700)	$ 286,200
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, 2013 and 2012 was approximately $185,000 and $113,000 respectively. Future non-cancellable minimum lease payments are approximately $132,000 for 2014, $72,000 for 2015, $62,000 for 2016 and $58,000 for 2017. We received rental income from sub rentals of $37,000 in 2013 and $50,000 in 2012.

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, 2013, we have no reserve for environmental remediation and are not aware of any environmental claims.

As of December 31, 2013, 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, 2013 and December 31, 2012.

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

	Year Ended December 31, 2013	2012
Statutory tax rate	34.0 %	34.0 %
Derivative instruments	11.8 %	(94.8)%
Oil and gas costs and long-lived assets	(6.3)%	30.7 %
Non-deductible expenses	(5.8)%	14.9 %
Change in valuation allowance	(33.7)%	15.2 %
Effective tax rate	0.0 %	0.0 %

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

	Year Ended December 31, 2013	2012
Non-current deferred tax asset:		
Oil and gas costs and long-lived assets	$ -	$ 698,339
Derivative instruments	921,771	612,139
Net operating loss carry-forward	9,138,048	8,010,770
Valuation allowance	(9,319,900)	(9,321,248)
Net deferred tax asset	739,919	-
Non-current deferred tax liability:		
Oil and gas costs and other Black Raven assets	(739,919)	-
Net deferred tax asset (liability)	$ -	$ -

At December 31, 2013, we have a net operating loss carry forward of approximately $74 million expiring in 2021-2033 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 $57.9 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, 2013.

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	$ -	$ 1,351,350	$ -
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, 2013:

	Term	Monthly Volumes[1]	Price/Bbl	Fair Value
Crude oil swap	1/13-12/15	1,600 Bbls	$ 76.74	$ (662,068)
Crude oil swap	7/11-12/15	2,625 Bbls	$ 83.70	(523,560)
Crude oil swap	1/14-12/14	1,369 Bbls	$ 90.25	(100,150)
Crude oil swap	1/14-12/14	1,900 Bbls	$ 96.00	(8,208)
Crude oil swap	1/15-12/15	5,800 Bbls	$ 88.55	(13,804)
Crude oil swap	1/13-12/14	3,000 Bbls	$ 95.15	(43,560)
				$ (1,351,350)

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

The total fair value is shown as a derivative instrument in both the current and non-current liabilities on the balance sheet. We recorded losses on the derivative contracts for the years ended December 31, 2013 and 2012 of $740,456 and $871,331 respectively.

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.

Potential common shares as of December 31, 2013 include 3,467,000 stock options and 4,779,460 shares from the conversion of preferred shares. Potential common shares as of December 31, 2012 include 250,000 warrants, 1,685,000 stock options and 4,779,460 from the conversion of preferred shares.

Note 12 - Accounts Payable

The Company's current liabilities at December 31, 2013 and 2012 include accounts payable in the amount of $2,424,009 and $2,384,090 respectively. The accounts payable balances for 2012 included $492,134 payable to Husch Blackwell LLP that was in dispute. On December 19, 2013, the Company reached an agreement to settle the dispute regarding this amount, and it was removed from our balance sheet and is not reflected as a liability as of December 31, 2013.

Note 13 - Note Payable

On November 30, 2012 the Company purchased two million shares of stock from a shareholder of the Company for $323,035 in cash (including an option payment that we previously made to the selling stakeholder) and a note payable of $825,000 bearing interest at a rate per annum of twenty-four hundredths percent (0.24%). Principal and accrued interest were payable quarterly. This note was retired in 2013.

Note 14 - Subsequent Events

On March 14, 2014, Black Raven Energy, Inc. (“Black Raven”), a wholly-owned subsidiary of EnerJex Resources, Inc., a Nevada corporation, entered into a Settlement and Release Agreement (the “Settlement Agreement”) with Atlas Resources, LLC (“Atlas” and, together with Black Raven, individually a “Party” and together the “Parties”) pursuant to which the Parties settled certain disputes regarding the rights and obligations of the Parties under that certain Farmount Agreement dated effective as of July 23, 2010 (the “Farmount Agreement”).

Pursuant to the Settlement Agreement, among other matters, the Parties released each other from certain claims and obligations, the Farmount Agreement was terminated, and the Parties entered into a new Gathering Agreement and Contract Operating Agreement under which Atlas shall pay to Black Raven an Overhead Charge of $12,000 per month from December 1, 2013 through November 30, 2015. Unless the Contract Operating Agreement is terminated at the option of either Party after November 30, 2015, from and after December 1, 2015, the Overhead Charge per month shall be the lesser of (a) $12,000, and (b) an amount equal to $0.25 per thousand cubic feet of natural gas produced in each such month from wells that Black Raven operates for Atlas pursuant to the Contract Operating Agreement.

Pursuant to the Settlement Agreement, Atlas also agreed to pay Black Raven the sum of $687,938.50 and assign to Black Raven its rights to depth in any zone below the Niobrara formation on approximately 8,360 acres that are held by production in Phillips and Sedgwick Counties in the State of Colorado. In addition, Black Raven agreed to purchase seven non-producing wells from Atlas for the sum $150,000.

Note 15 - 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, 2013	Year Ended December 31, 2012
Production revenues	$ 10,942,270	$ 8,496,519
Production costs	(4,095,850)	(3,102,321)
Depletion and depreciation	(1,691,008)	(1,541,069)
Income tax	(1,752,840)	(1,305,513)
Results of operations for producing activities	$ 3,402,572	$ 2,547,616

Capitalized costs

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
Unevaluated properties not subject to amortization	$ -	$ 7,830,828
Properties subject to amortization	71,917,308	30,466,951
Capitalized costs	71,917,308	38,297,779
Accumulated depletion	(10,567,905)	(5,094,881)
Net capitalized costs	$ 61,349,403	$ 33,202,898

Cost incurred in property acquisition, exploration and development activities

	Year Ended December 31, 2013	Year Ended December 31, 2012
Acquisition of properties	$ 124,028	$ -
Exploration costs	-	-
Development costs	7,484,419	10,247,539
Net capitalized costs	$ 7,608,447	$ 10,247,539

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, 2013	Year Ended December 31, 2012
Proved reserves (BOE):		
Beginning	2,927,000	2,714,150
Revisions of previous estimates	141,600	(193,059)
Purchase of minerals in place	2,685,517	-
Extension and discoveries	175,917	502,751
Sale of minerals in place	(4,800)	-
Sale of Rantoul Partners interest	-	-
Production	(120,634)	(96,842)
Ending	5,804,600	2,927,000

Proved developed reserves for December 31, 2013 consisted of 83% oil and 17% natural gas and totaled 3,824.9 MBOEs. Proved developed reserves for December 31, 2012 consisted of 100% oil and totaled 1,546.3 MBOEs. Proved undeveloped reserves for December 31, 2013 were 1,979.9 MBOEs. Proved undeveloped reserves at December 31, 2012 were 1,380.8 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, 2013	Year Ended December 31, 2012
Future production revenue	$ 413,965,250	$ 246,535,000
Future production costs	(122,957,721)	(69,131,000)
Future development costs	(20,017,885)	(11,766,000)
Future cash flows before income tax	270,989,644	165,638,000
Future income taxes	(56,111,563)	(33,550,000)
Future net cash flows	214,878,081	132,088,000
10% annual discount for estimating of future cash flows	(133,430,425)	(83,215,000)
Standardized measure of discounted net cash flows	$ 81,447,656	$ 48,873,000

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, 2013	Year Ended December 31, 2012
Balance beginning of year	$ 48,872,561	$ 43,646,905
Sales, net of production costs	(6,846,420)	(5,394,198)
Net change in pricing and production costs	(11,143,669)	2,870,156
Net change in future estimated development costs	(2,281,285)	(1,001,445)
Purchase of minerals in place	32,687,100	-
Extensions and discoveries	3,342,922	11,274,543
Sale of minerals in place	(37,375)	-
Sale of Rantoul Partners interest	-	-
Revisions	1,357,734	(4,329,483)
Accretion of discount	16,563,800	5,324,900
Change in income tax	(1,067,712)	(3,518,817)
Balance end of year	$ 81,447,656	$ 48,872,561