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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, 2016
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 10% Series A Cumulative Redeemable Perpetual Preferred Stock, $0.001 par value

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer ¨

Non-accelerated filer ¨ (Do not check if a smaller reporting company) Smaller reporting company x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

¨ Yes x No

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 $2.4 million based on a share value of $.28.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 8,423,936 shares of common stock, $0.001 par value, outstanding on March 31, 2017.

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.

ENERJEX RESOURCES, INC.
FORM 10-K
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FORWARD-LOOKING STATEMENTS

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

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

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

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

AVAILABLE INFORMATION

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

INDUSTRY AND MARKET DATA

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

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES.

Company History

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

Liquidity and Ability to Continue as a Going Concern

As discussed under "Item 9B — Other Information" the continued low oil and natural gas prices during 2015 and 2016 have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

In addition, as discussed below under "Significant Developments in 2016 and Recent Developments" the Company's lender sold our loan on February 10, 2017.

We agreed with the successor lender to several simultaneous transactions –

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter int™o a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,00.

2. we would:

   a. convey our oil and gas properties and associated performance and surety bonds in Colorado, Texas, and Nebraska, and

   b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

   c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company's oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon Enerjex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

We are required to obtain stockholder approval of this proposed transaction.

Significant Developments in 2016 and Recent Developments

The following briefly describes our most significant corporate developments occurring in 2016:

On April 1, 2016 the Company informed Texas Capital Bank ("TCB") that it would cease making the mandatory monthly borrowing base reduction payments and did not make the required April 1, 2016 payment. The Company made its mandatory quarterly interest payments on April 6, 2016, and May 2, 2016. On April 7, 2016 the Company entered into a Forbearance Agreement whereby TCB agreed to not exercise remedies and rights afforded it under the Amended and Restated Credit Agreement for thirty days. The 30-day period was to be used by the Company to pursue strategic alternatives.

On April 28, 2016 TCB informed the Company that it would extend the above Forbearance Agreement period to May 31, 2016 upon effecting a principal reduction of $125,000. On May 31, 2016, the Company and TCB amended the Forbearance Agreement to extend the forbearance period to August 31, 2016. On July 29, 2016, the Company and TCB amended the Forbearance Agreement to extend the forbearance period to October 1, 2016.

On October 1, 2016, the Company and TCB could not reach an agreement to extend the Third Amendment to the Forbearance Agreement. Following this outcome, the Company decided to discontinue payment of interest on its outstanding loan obligations with TCB. The Company continued to evaluate plans to restructure, amend or refinance existing debt through private options.

On October 26, 2016 the NYSE delisted our Series A preferred stock from the NYSE MKT due to the failure to maintain a market capitalization of above $1 million. On January 11, 2017, we announced that we received a letter of noncompliance from the NYSE by reason to hold an annual meeting for the fiscal year ended December 31, 2015. On January 17, 2017, we announced that the NYSE had accepted our plan to restore compliance with certain NYSE regulations on or before March 31, 2017. The NYSE has granted an extension due to the inability to complete this Annual Report on Form 10K in time to have a stockholder meeting by that date. The holding of this stockholder meeting is part of our plan to restore compliance.

On February 10, 2017, the Company, TCB and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into a Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022, Buyer may acquire the interest in clause (ii) above. In connection with the LSA, the Company release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and successor lender entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the “letter agreement”) pursuant to which:

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

    a. convey our oil and gas properties and associated performance and surety bonds in Colorado, Texas, and Nebraska, and

    b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

    c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company’s oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

The Closing is expected to occur on or before May 1, 2017 (the February 10, 2017 letter agreement provided for a Closing on or before April 30, 2017. This was amended to May 1, 2017 in the amendment).

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, 2016 were 1.6 million barrels of oil equivalents (BOE), of which 64.1% was natural gas. Of the 1.6 million BOE of total proved reserves, approximately 12.2% are classified as proved developed producing, approximately 42.3% are classified as proved developed non-producing, and approximately 45.5% are classified as proved undeveloped.

The total PV10 (present value) of our proved reserves as of December 31, 2016 was approximately $3.4 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 after giving consideration of salvage value there were no material abandonment costs included in future development 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 36, 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, 2016.

Our Colorado Properties

The table below summarizes our current Colorado and Nebraska acreage by project name as of December 31, 2016.

Project Name	Developed Acreage (1)		Undeveloped Acreage		Total Acreage	
	Gross	Net (2)	Gross	Net (2)	Gross	Net (2)
Adena	18,280	18,280	-	-	18,280	18,280
Hereford	-	-	3,400	3,400	3,400	3,400
Seven Cross	640	544	-	-	640	544
Niobrara	21,773	21,010	12,167	10,315	33,940	31,325
Total	40,693	39,834	15,567	13,715	56,250	53,549

(1) Developed acreage includes all acreage that was held by production as of December 31, 2016.

(2) Net acreage is based on our net working interest as of December 31, 2016.

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 18,280 gross acres as of December 31, 2016. 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. The 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 the Adena Field were temporarily abandoned or shut-in during the mid-1980's when oil prices collapsed, and a relatively small number of wells have been produced since that time.

Approximately 112 wells on our acreage are currently shut-in or temporarily abandoned. Our current understanding of the field indicates that most of the remaining 97 shut-in oil wells are candidates for reactivation, recompletion or use in a larger scale EOR project. The same is true for the remaining 14 shut-in injection wells. We have a significant EOR project study under way at the present time and have begun field sampling and EOR flood modeling for each project. We intend to reactivate vintage secondary recovery injection wells simultaneously with the reactivation and/or recompletion of producer wells. Recompletions and reactivations are expected to cost approximately $200,000 to $250,000 per well and are expected to result in stabilized production rates of approximately 10 barrels of oil per day. We have also identified a number of wells on our acreage that are prospective for natural gas production from the J-Sand and D-Sand formations.

As of December 31, 2016, the Adena Field Project was producing approximately 75 gross barrels of oil per day from 9 J-Sand wells and 2 D-Sand wells at a depth of approximately 5,500 feet. One J sand gas producer was temporarily shut-in because of low natural gas prices and due to reservoir management practices. Multiple wells are off production because they require maintenance work; however, we have delayed maintenance expenditures due to low commodity prices. We intend to pursue our reactivation and recompletion strategy once oil prices recover.

Our working interest in the 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 $39.5 million at December 31, 2016).

Niobrara – Colorado & Nebraska

Our Niobrara Project is located in the northeastern portion of the D-J Basin, where we owned a 100% working interest in approximately 34,000 gross acres as of December 31, 2016. Our acreage is located in Phillips and Sedgwick Counties, Colorado, and Perkins County, Nebraska.

Approximately 21,000 developed acres in this project are held by production and approximately 12,000 undeveloped acres are held by leases. As of December 31, 2016, 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 Titan Energy. All of these wells are located in Amherst Field in Phillips and Sedgwick Counties, Colorado. As of December 31, 2016, we produced approximately 90 net mcf of natural gas per day from the Niobrara formation at a depth of approximately 2,500 feet.

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

DJ Basin Resource Play Exposure

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

Our Kansas Properties

The table below summarizes our current Kansas acreage by project name as of December 31, 2016.

Project Name	Developed Acreage [1]		Undeveloped Acreage		Total Acreage	
	Gross	Net [2]	Gross	Net [2]	Gross	Net [2]
Mississippian Project	4,365	3,492	-	-	4,365	3,492
Other	584	146	-	-	584	146
Total	4,949	3,638	-	-	4,949	3,638

(1) Developed acreage includes all acreage that was held by production as of December 31, 2016.

(2) Net acreage is based on our net working interest as of December 31, 2016.

Mississippian Project

Our Mississippian Project is located in Woodson and Greenwood Counties in Southeast Kansas, where we own a 90% working interest in 4,949 gross acres. Approximately 73.5% of the gross leased acres in this project are currently held-by-production.

As of December 31, 2016, our Mississippian Project was producing approximately 100 gross barrels of oil per day from the Mississippian formation at a depth of approximately 1,700 feet.

Cherokee Project

On August 12, 2015, EnerJex Resources, Inc., through its subsidiaries, EnerJex Kansas, Inc., and Working Interest, LLC, sold the Cherokee Project for approximately $2.8 million to Haas Petroleum, LLC, BAM Petroleum, LLC and MorMeg, LLC. The effective date of the sale was July 1, 2015.

Our Texas Properties

The table below summarizes our current Texas acreage by project name as of December 31, 2016.

Project Name	Developed Acreage (1)		Undeveloped Acreage		Total Acreage	
	Gross	Net (2)	Gross	Net (2)	Gross	Net (2)
El Toro Project	458	275	-	-	458	275
Total	458	275	-	-	458	275

(1) Developed acreage includes all acreage that was held by production as of December 31, 2016.

(2) Net acreage is based on our net working interest as of December 31, 2016.

El Toro Project

Our El Toro Project is located in Atascosa and Frio Counties in South Texas. As of December 31, 2016 we owned a 60% working interest in 458 gross acres. As of December 31, 2016, this project was producing approximately 7 gross barrels of oil per day from the Olmos formation at a depth of approximately 4,500 feet.

Our Business Strategy

Our principal strategy focuses on the development of oil and gas properties that have low production decline rates and offer 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 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.

- *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:

- the market price for oil, gas and natural gas liquids;

- our ability to preserve sufficient working capital and maintain access to capital resources;

- our ability to cost effectively manage our operations;

- our ability to source and evaluate potential projects;

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

- our ability to implement development program.

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, 2016 and the year ended December 31, 2015.

Drilling Activity

	Gross Wells			Net Wells [1]		
Fiscal Year	Total	Successful	Dry	Total	Successful	Dry
2016 - Development	-	-		-	-	
2015 - Development	-	-	-	-	-	-
2015 - Exploratory	2	-	2	1.0	-	1.0
2016 - Recompletion	-	-	-	-	-	-
2015 - Recompletion	-	-	-	-	-	-

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

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

The table below sets forth our net oil and gas production (net of all royalties, overriding royalties and production due to others) for the years ended December 31, 2016 and 2015, the average sales prices, average production costs and direct lifting costs per unit of production.

	Year ended December 31, 2016	Year ended December 31, 2015
Net Production		
Crude oil (bbl)	58,123	96,244
Natural gas liquids (bbl)	530	6,045
Natural gas (mcf)	47,554	188,408
Average Sales Prices		
Crude oil ($ per bbl)	40.75	44.24
Natural gas liquids ($ per bbl)	7.02	4.01
Natural gas (per $ mcf)	1.51	1.88
Average Production Cost (1) $ per BOE	43.79	41.96
Average Lifting Costs (2) $ per BOE	39.97	33.67

(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, 2016 and 2015. 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, 2016	Year Ended December 31, 2015
Production revenues	$ 2,461,727	$ 4,878,722
Production costs	(2,661,258)	(4,501,940)
Depreciation, depletion and amortization	(254,329)	(1,108,039)
Results of operations for producing activities	$ (453,860)	$ (731,257)

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, 2016.

Project	Active Gross	Active Net (1)
Crude Oil		
El Toro Project	12	7.2
Mississippian Project	244	219.6
Adena Field Project	27	27.0
Other	3	2.6
Total Oil	286	256.4
Natural Gas		
Niobrara Project	24	24.0
Total Gas	24	24.0

(1) Net wells are based on our net working interest as of December 31, 2016.

Reserves

Proved Reserves

The estimated total PV10 (present value) of our proved reserves as of December 31, 2016 was $3.4 million, compared to $8.8 million as of December 31, 2015. Our total net proved oil and gas reserves as of December 31, 201 were 1.6 million BOE (64.1% natural gas), compared to 2.6 million BOE (59.4% oil) as of December 31, 2015. Of the 1.6 million net BOE of total proved reserves at December 31, 2016, approximately 12.2% are classified as proved developed producing, approximately 42.3% are classified as proved developed non-producing, and approximately 45.5% are classified as proved undeveloped. See "Glossary" on page 17 for our definition of PV10.

The estimated PV10 of the 1.6 million BOE is set forth in the following table. The PV10 is calculated using an average net oil price of $37.36 per barrel, an average net natural gas price of $1.65 per mcf and an average natural gas liquids price of $8.55 per barrel, and by applying an annual discount rate of 10% to the forecasted future net cash flow.

In 2016 the Company invested approximately $17,100 in its oil and gas properties. These reduced expenditures were in response to extremely low commodity prices. The Company has approximately $1.7 million of current asset on hand and important infrastructure in Colorado completed which will facilitate the exploitation and development of proved undeveloped reserves over the next five years. At year end the Company's review of proved undeveloped reserves revealed challenges but the Company maintains its belief that reserves will be developed within five years of their initial recording as a proved undeveloped reserve. In addition it believes it has the financial wherewithal to develop all it's proved undeveloped reserves within the five year time frames required; utilizing its balance sheet, to borrow funds as needed and it has the ability to joint venture any of its assets.

Summary of Proved Oil and Gas Reserves
December 31, 2016

	Gross				Net				
Proved Reserves Category	Crude Oil BBL's	Natural Gas Liquids BBL's	Natural Gas MCF's	Oil Equivalents BOE's	Crude Oil BBL's	Natural Gas Liquids BBL's	Natural Gas MCF's	Oil Equivalents BOE's (1)	PV 10 (2) (before tax)
Proved, Developed	488,580	56,320	4,827,420	1,349,470	372,140	44,780	2,686,800	864,720	2,120,330
Proved, Undeveloped	196,860	-	4,176,000	892,860	152,610	-	3,422,170	722,970	1,316,700
Total Proved	685,440	56,320	9,003,420	2,242,330	524,750	44,780	6,108,970	1,587,690	3,437,030

(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, 2016.

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 2016, we sold oil to ARM Energy Management LLC, Coffeyville Resources, Inc., and Sunoco Logistics, Inc. on a month-to-month basis (i.e., without a long-term contract). We sold our natural gas to United Energy Trading on a month-to-month basis and Western Operating Company under a long-term contract. 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. We had an ISDA master agreement and a deferred premium put options with BP through December 31, 2016.

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 water flooding, 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 water flooding 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 water flood 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 emerging market economies, notably India and China. North American prospects became more attractive as oil prices rose worldwide. 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. In 2016 we had month-to-month sales contracts with ARM Energy Management LLC, Coffeyville Resources, Inc., Sunoco Logistics, 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; 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 10 full-time employees, two temporary employee and one part-time employee 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

Executive offices are maintained at 4040 Broadway, Suite 508, San Antonio, Texas 78209 under a lease expiring November 2017. We also have a field office located at 165 South Union Blvd, Suite 410, Lakewood Colorado 80228, under a lease which expires October 2019.

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

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

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 water flooding. Normally, natural gas is injected into the natural gas cap and water is injected into the production zone to sweep oil and gas from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form of enhanced recovery.
Stock Tank Barrel or STB	A stock tank barrel of oil and gas is the equivalent of 42 U.S. Gallons at 60 degrees Fahrenheit.
Undeveloped Acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.
Unitize, Unitization	When owners of oil and gas reservoir pool their individual interests in return for an interest in the overall unit.
Water flood	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 water flood.
Water Supply Wells	A well in which fluids are being produced for use in a water injection well.
Wellbore	A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open. Also called a borehole or hole.
Working Interest	An interest in an oil and gas lease entitling the owner to receive a specified percentage of the proceeds of the sale of oil and gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and gas.

ITEM 1A. RISK FACTORS.

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

Risks Related to Recent Developments

Due to our substantial liquidity concerns, we may be unable to continue as a going concern.

On February 10, 2017, our lender sold our secured loan to PWCM Investment Company IC LLC, and certain financial institutions (collectively, the "successor lender") pursuant to a loan sale agreement between Enerjex, our former lender, and the successor lender. The successor lender purchased from our prior lender all of its right, title and interest in, to and under our credit agreement and loan documents, in exchange for (i) a cash payment of $5,000,000, (ii) a synthetic equity interest equal to 10% of the proceeds, after successor lenders realization of a 150% return on the cash purchase price within 5 years of the closing date, and (iii) at any time prior to February 10, 2022, Buyer may acquire the synthetic equity interest above. In connection with the loan sale agreement, we released our prior lender and its successors, including the successor lender, from any and all claims under the credit agreement and loan documents. The Company is seeking stockholder approval of this transaction at the annual meeting of its stockholders to be held on April 27, 2017.

Also on February 10, 2017, we and our subsidiaries and the successor lender entered into a binding letter agreement dated February 10, 2017, pursuant to which the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000. So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

As consideration for the loan forgiveness, and subject to obtaining stockholder approval prior to the closing, we agreed to convey to successor lender all of our right, title, and interest, in and to all real property leases and oil and gas producing properties and other assets situated in the States of Colorado, Texas and Nebraska, including all our equipment and tangible personal property owned and used in connection with our ownership and operation of those real property leases and oil and gas producing properties. The assets we are conveying (i) shall include our assets in the Adena Field, the NECO Project, Weld County, East Crown and certain other oil and gas plugging, lease and other bonds. Subject to obtaining shareholder approval prior to the closing, we will also transfer to successor lender all of our right, title, and interest in and to all our Oakridge Energy, Inc. shares.

If this transaction closes, we will retain the Kansas-based assets, which currently generate a majority of our revenue and cash flow from operations, and the successor lender will agree that the conveyance of all of our other oil and gas assets, the Oakridge Energy shares, and the restated secured note in the principal amount of $4,500,000, payable with a discount at $3,300,000 provided the loan is paid in full prior to the maturity date November 1, 2017, subject to extension. We are seeking stockholder approval of that transaction at the annual meeting of its stockholders scheduled for April 27, 2017.

Due to our indebtedness, liquidity issues and the potential for restructuring transactions, there is risk that, among other things:

- it may become more difficult to retain, attract or replace key employees;
- employees could be distracted from performance of their duties or attracted to other career opportunities; and
- our suppliers, hedge counterparties, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events has already negatively affected our business and may continue to have a material adverse effect on our business, results of operations and financial condition.

The Closing is expected to occur on or before May 1, 2017.

Should we not be able to close this transaction, our existing and future debt agreements could create issues as principal and interest payments become due and the debt matures that will threaten our ability to continue as a going concern. We will likely seek bankruptcy protection if this transaction is not approved by the stockholders.

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.

While our bank sold its rights under our credit facility to the successor lender, and the successor lender has agreed to a transaction in which we can contribute certain of our assets, our shares in Oakridge Energy, and reduce our loan amount from $17,925,000 to a restated note in the original principal amount of $4,500,000, subject to a $1,200,000 discount provided that we repay the successor lender $3,300,000 prior to the maturity date of November 1, 2017 (subject to extension). In exchange we can retain our Kansas oil and gas assets. Unless and until this transaction closes (which is dependent on the approval of our stockholders), we will remain in default on our obligations, and the successor lender may enforce its rights as secured parties and we will likely lose all of our Kansas assets and may be forced to liquidate the Company.

We are unable to fulfill our obligations under our credit facility which is adversely affecting our business.

As of December 31, 2016, we had total indebtedness of $17,925,000 under the credit facility and our borrowing base was $17,925,000. 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. With the signing of the "Eleventh Amendment" on November 13, 2015 certain covenants were waived until December 31, 2016. With these covenants waived, we were incompliance with the affirmative covenant provisions of the credit facility.

We are currently unable to comply with some or all of these covenants. If we do not obtain waivers from the successor lender, we would be unable to make additional borrowings under these facilities; our indebtedness under these agreements would remain in default and repayment of debt could be accelerated. If our indebtedness is accelerated, we will 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.

Our 2016 oil and gas reserve report shows a material decline in our estimated reserves, which will have adverse implications to our business.

Our 2016 oil and gas reserve report shows a material decline in our estimated reserves. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For example, estimates of quantities of proved reserves and their PV10 value are affected by changes in crude oil and gas prices, because estimates are based on prevailing prices at the time of their determination. Further, reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary from one another.

The reduction in our reserve estimates is likely to change the schedule of future production and development drilling that was contemplated in our 2015 reserve report. Reserve estimates are generally different, and often materially so, from the quantities of oil and natural gas that are ultimately recovered. Furthermore, estimates of quantities of proved reserves and their PV10 value may be affected by changes in crude oil and gas prices because the Company’s estimates are based on prevailing prices at the time of their determination.

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

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

We may continue to 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.

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. For the year ended December 31, 2015 impairment charges of $48,930,087 were recorded. For the year ended December 31, 2016 impairment charges of $8,032,670 were recorded.

Our stock price has declined below $1.00 per share. If the average closing price of our common stock is less than $1.00 per share for a period of over 30 consecutive trading days, the NYSE could delist our common stock.

The NYSE requires that the average closing price of a listed company’s common stock not be less than $1.00 per share for a period of over 30 consecutive trading dates. Under NYSE rules, a company can avoid delisting, if, during the six month period following receipt of the NYSE notice and on the last trading day of any calendar month, a company’s common stock price per share and 30 trading-day average share price is at least $1.00. During this six month period, a company’s common stock will continue to be traded on the NYSE, subject to compliance with other continued listing requirements.

In the future, if our common stock ultimately were to be delisted for any reason, it could negatively impact us by (i) reducing the liquidity and market price of our common stock; (ii) reducing the number of investors willing to hold or acquire our common stock, which could negatively impact our ability to raise equity financing; (iii) limiting our ability to use a registration statement to offer and sell freely tradeable securities, thereby preventing us from accessing the public capital markets; and (iv) impairing our ability to provide equity incentives to our employees.

Risks Associated with our Industry

Oil and gas prices are volatile. Future price volatility may negatively impact cash flows which could result in an inability to cover our operating and/or capital expenditures.

Our future revenues, profitability, future growth and the carrying value of our properties depend substantially on the prices we realize for our oil and gas production. Our realized prices may also affect the amount of cash flow available for operating and/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 and war;
- domestic and foreign governmental regulations and taxation;
- political and economic conditions in oil and gas producing countries, including those in the Middle East and South America;
- impact of the U.S. dollar exchange rates on oil and gas prices;
- the availability of refining capacity;
- actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state controlled oil and gas companies relating to oil and gas price and production controls; and
- the price and availability of other fuels.

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

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

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

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

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

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

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

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

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

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

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

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

Approximately 45.5% of our total proved reserves as of December 31, 2016 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, 2016 was $3.4 million, versus $8.8 million as of December 31, 2015. Of the 1.6 million BOE of total proved reserves, approximately 12.2% are classified as proved developed producing, approximately 42.3% are classified as proved developed non-producing, and approximately 45.5% 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. For further information please see the disclosures in Footnote 14 to the Notes to the Financial Statements.

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, 2016 were prepared by Cobb & Associates, Inc., 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 Cobb & Associates, Inc. in accordance with rules of the Securities and Exchange Commission, or SEC, and are not intended to represent the fair market value of such reserves.

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

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

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

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

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

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

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

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

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

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

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

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

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

Developing and exploring for oil and gas involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oil and gas field equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil and gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. 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. In 2015 we had a carried interest in the drilling of two exploratory wells and we drilled no developmental wells.

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 water flood 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 water flood 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 if 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.

In Kansas, we sell oil to Coffeyville Resources. There are approximately six 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 Logistics, Inc. in Texas. There are numerous purchasers in Texas, but increased production volumes from extensive shale drilling activity in the area could result in reduced purchases by several of our purchasers.

In Colorado we sell oil to ARM Energy Management LLC. There are a number of potential purchasers of our oil in Colorado but increased production volumes from the DJ basin could 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 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.

Risks Associated with our Stock

We have ceased paying dividends on our Series A preferred stock, causing the trading price of the preferred stock to dramatically decline

On November 4, 2015, we announced that we would not be declaring the monthly dividend for the month of November 2015 on our 10.00% Series A Cumulative Redeemable Perpetual Preferred Stock in order to preserve our cash resources. We have not declared the monthly dividend since, and do not expect to do so in the near future. The failure to declare and pay monthly dividends on our preferred stock caused its trading price to decline substantially.

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

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

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

Our directors, officers and principal stockholders (stockholders owning 10% or more of our common stock) and their affiliates beneficially owned approximately 3,973,168 shares or 47.17% of the outstanding shares of common stock, stock options, and derivatives that could have been converted to common stock at December 31, 2016, and as of the filing of this Annual Report on Form 10-K. Such stockholders will have significant influence over the outcome of all matters submitted to our stockholders for approval, including the election of directors and other corporate actions.

Two of our Directors, Ryan A. Lowe and Lance W. Helfert, served on the investment committee of West Coast Asset Management, Inc. West Coast Asset Management was 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 Opportunity Fund, LLC was terminated in July 2015 and all of the assets of the fund, including EnerJex common and preferred shares were distributed to the shareholders of that fund. West Coast Asset Management's principals also manage Montecito Venture Partners, LLC. Montecito Venture Partners, LLC beneficially owned 1.53% of our common stock and .7% of our Series A preferred stock at December 31, 2016 and as of the date of this filing. West Coast Asset Management, Inc. was dissolved in September 2016.

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

As stated above, Montecito Venture Partners affiliates of our directors Mr. Lowe and Mr. Helfert, beneficially own, as of December 31, 2016, 1.53% of our common stock and .7% of our Series A preferred stock. The interests of Montecito Venture Partners, and their affiliates, may differ from those of our other stockholders. 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy with regard to our common stock is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, investment opportunities and restrictions contained in current or future financing instruments, including the consent of debt holders and holders of Series A Shares, if applicable at such time, and other factors our Board of Directors deems relevant.

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.

On September 23, 2016 the Company, American Standard Energy Corporation, Baylor Operating LLC, Bernard Given and Loeb & Loeb LLP were sued by Geronimo Holdings Corporation and Randal Capps in the 143rd Judicial District Court located in Pecos, Texas. The suit among other things, seeks damages for an alleged unlawful sale of properties in Crockett County Texas and for alleged unpaid royalties. The Company believes the suit is without merit and will vigorously defend itself. The Company has faith that it will prevail and at December 31, 2016 no reserve for potential losses arising from this matter has been recorded. Additionally under its agreement with Baylor Operating LLC, Baylor has agreed to indemnify and defend the Company against all lawsuits and claims including this one.

On April 26, 2016 C&F Ranch, LLC sued the Company in Allen County Kansas for alleged breach of contract related to the rental of certain lands located on the C&F Ranch. The Company believes that has paid all rents owe to C&F Ranch LLC and will vigorously defend itself. The Company has faith that it will prevail and at December 31, 2016 no reserve for potential losses arising from this matter has been recorded.

ITEM 4. MINE SAFETY DISCLOSURE

None

PART II

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

Market Information for Common Stock

Our common stock trades on the NYSE MKT under the symbol "ENRJ." The following table lists the quotations for the high and low sales prices of our common stock for the years ended December 31, 2015 and December 31, 2016. 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, 2015		
Quarter ended March 31, 2015	$ 3.44	$ 1.21
Quarter ended June 30, 2015	$ 2.19	$ 1.25
Quarter ended September 30, 2015	$ 1.53	$ .49
Quarter ended December 31, 2015	$ .93	$ .30
Year Ended December 31, 2016		
Quarter ended March 31, 2016	$ .38	$ .20
Quarter ended June 30, 2016	$ .38	$ .23
Quarter ended September 30, 2016	$ .61	$ .25
Quarter ended December 31, 2016	$ .40	$ .26

Holders

As of March 31, 2017, there were 341 holders of record of our common stock, and 9 holders of record of our Series A preferred stock.

Dividends

We have never paid or declared any cash dividends on our common stock. Through October 2015, we paid a monthly dividend of $.20833 per share or $2.50 annual dividend per share on the Company's non-convertible 10.0% Series A Cumulative Redeemable Perpetual Preferred Stock. On November 4, 2015 the Company suspended the monthly dividend for the month of November 2015 on its 10.00% Series A Cumulative Redeemable Perpetual Preferred Stock ("Series A Preferred Stock") in order to preserve its cash resources. Payment of future dividends on the Series A Preferred Stock will be determined by the Company's Board of Directors.

Under the terms of the Series A Preferred Stock, the dividend for the month of November 2015, and any future unpaid dividends, will accumulate. If the Company does not pay dividends on its Series A Preferred Stock for six monthly periods (whether consecutive or non-consecutive), the dividend rate will increase to 12.0% per annum and the holders of the Series A Preferred Stock will have the right, at the next meeting of stockholders, to elect two directors to serve on the Company's Board of Directors along with other members of the Board, until all accumulated accrued and unpaid dividends are paid in full.

We do not expect to pay any cash dividends on our common stock in the foreseeable future. Additionally, 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

The following table sets forth information as of fiscal year ended December 31, 2016, 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	207,665	$ 9.69	507,825

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA.

Not applicable.

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

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

Overview

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

Results of Operations

The following table presents selected information regarding our operating results from continuing operations.

	Year Ended December 31, 2016	Year Ended December 31, 2015	Difference
Oil & gas revenues [(1)]			
Crude oil revenues	$ 2,390,024	$ 4,525,089	$ (2,135,065)
Average price per Bbl	40.75	44.24	(3.49)
Natural gas revenues	71,703	353,633	(281,930)
Average price per Mcf	1.51	1.88	(.37)
Expenses:			
Lease operating expenses [(2)]	2,661,258	4,501,940	(1,840,682)
Depreciation, depletion and amortization [(3)]	254,329	1,108,039	(853,710)
Impairment of oil and gas properties	8,032,670	48,930,087	(40,897,417)
Total production expenses	10,948,257	54,540,066	(43,591,809)
Professional fees [(4)]	310,471	680,860	(370,389)
Salaries [(5)]	1,642,593	1,927,552	(284,959)
Depreciation - other fixed assets	159,638	203,407	(43,769)
Administrative expenses [(6)]	539,571	636,459	(96,888)
Total expenses	$ 13,600,530	$ 57,988,344	$ (44,387,814)

[(1)] 2016 crude oil revenues decreased $2.1 million or 47% to 2.4 million from $4.5 million in fiscal 2015. This decrease was due to the continued decline in crude oil prices. Realized oil prices dropped $3.49 or 8% during 2016 from an average of $44.24 per bbl in 2015 to an average of $40.75 per bbl in 2016. Declining prices accounted for approximately $200,000 of the $2.1 million drop in crude oil revenues. A decrease in production volumes in 2016 accounted for $1.9 million of the $2.1 million decrease in revenues. Volumes decreased by approximately 43,600 bbls or 43% to 58,653 bbls in 2016 compared to production of 102,289 bbls in 2015. 2016 natural gas revenues decreased approximately $282,000 or 80% to $71,700 from $353,600 million in 2015. The decrease was due to lower natural gas prices in 2016. Natural gas prices decreased $.37 per mcf or 20% from an average price of $1.88 in 2015 to an average price of $1.51 in 2016. This drop in prices accounted for $69,100 of the overall $282,000 decrease in revenues. A decrease in production volumes accounted for the remaining $213,000 decrease in revenues. Natural gas volumes decreased approximately 140,900 mcf or 75% in 2016 from 188,400 mcf in 2015 to 47,600 mcf in 2016.

[(2)] 2016 lease operating expenses decreased $1.8 million or 41% to $2.7 million from $4.5 million in 2015. However, lease operating expenses per boe increased 19% or $6.30 to $39.97 in 2016 from $33.67 per boe in 2015.

[(3)] The depletion expense decrease is due primarily to the impairment of oil and gas properties necessitated by the SEC quarterly ceiling tests. The Company reviews the carrying value of oil and gas properties accounted for by use of the full cost rules of accounting. This method dictates that the net book value of oil and gas properties, less deferred income taxes, may not exceed a calculated "ceiling." 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 in the statement of operations. For the year ended December 31, 2015 impairments of $16,401,376, $11,421,613, $9,720,983 and $11,386,115 were record in the first, second, third and fourth quarters respectively. For the year ended December 31, 2016 impairments of $4,506,933, $2,137,663, $800,000 and $588,073were record in the first, second, third and fourth quarters respectively. Because of these write downs depletion expense per boe decreased 54% or $4.47 per boe from $8.29 per boe in 2015 to $3.82 per boe in 2016. As a result, 2016 depletion expense decreased approximately $854,000 to approximately $254,000 from $1,108,039 in 2015.

[(4)] Professional fees decreased 54% or approximately $370,000 thousand from approximately $681,000 in 2015 to approximately $310,500 in 2016. Investor relation expenditures decreased approximately $110,000 and Consulting fees including tax, third party engineering and audit decreased by approximately $308,000. These decreases were partially offset by increases in legal fees of approximately $48,000.

(5) Salaries decreased 15% or approximately $300,000. The decrease was due primarily to decreased head counts.

(6) Administrative expenses decreased approximately $97,000 or 15%. The decrease was due primarily to decreased spending on SEC matters, travel, training and office supplies of $122,000, $21,000, $30,000 and $18,000 respectively. These decreases were partially offset by an increase spending for IT and software and reduced recovers of overhead costs from a joint interest partner of $34,000 and $60,000 respectively.

Reserves

Proved Reserves		Year Ended December 31, 2016		Year Ended December 31, 2015
Total proved PV10 (present value) of reserves	$	3,437,030	$	8,769,970
Total proved reserves (BOE)	$	1,587,690	$	2,574,860
Average Price (per bbl)	$	37.36	$	50.28
Average Price (per mcf)	$	1.65	$	2.58

Of the 1.6 million BOE of total proved reserves, approximately 12.2% are classified as proved developed producing, approximately 42.3% are classified as proved developed non-producing, and approximately 45.5% are classified as proved undeveloped.

The following table presents summary information regarding our estimated net proved reserves as of December 31, 2016. 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 Cobb & Associates Inc., our independent petroleum consultants. For additional information regarding our reserves, please see Note 13 to our audited financial statements for the fiscal year ended December 31, 2016.

Summary of Proved Oil and Gas Reserves
December 31, 2016

	Gross				Net				
Proved Reserves Category	Crude Oil BBL's	Natural Gas Liquids BBL's	Natural Gas MCF's	Oil Equivalents BOE's	Crude Oil BBL's	Natural Gas Liquids BBL's	Natural Gas MCF's	Oil Equivalents BOE's (1)	PV 10 (2) (before tax)
Proved, Developed	488,580	56,320	4,827,420	1,349,470	372,140	44,780	2,686,800	864,720	2,120,330
Proved, Undeveloped	196,860	-	4,176,000	892,860	152,610	-	3,422,170	722,970	1,316,700
Total Proved	685,440	56,320	9,003,420	2,242,330	524,750	44,780	6,108,970	1,587,690	3,437,030

In 2016 the Company invested approximately $17,100 in its oil and gas properties. These reduced expenditures were in response to extremely low commodity prices. The Company has approximately $1.7 million of current asset on hand and important infrastructure in Colorado completed which will facilitate the exploitation and development of proved undeveloped reserves over the next five years. At year end the Company's review of proved undeveloped reserves revealed challenges but the Company maintains its belief that reserves will be developed within five years of their initial recording as a proved undeveloped reserve. In addition it believes it has the financial wherewithal to develop all it's proved undeveloped reserves within the five year time frames required; utilizing its balance sheet, to borrow funds as needed and it has the ability to joint venture any of its assets.

(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, 2016		As of December 31, 2015
PV10 (before tax)	$	3,437,030	$	8,769,970
Future income taxes, net of 10% discount	$	-	$	-
Standardized measure of discounted future net cash flows	$	3,437,030	$	8,769,970

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, asset sales and the issuance of equity securities. Due to the dramatic deterioration of oil prices, the resulting decline in our reserves as reflected in our reserve report which caused a corresponding reduction in our borrowing base, and the recent issuances of equity securities from our "shelf" registration, it will be more difficult in 2016 to use our historical means of meeting our capital requirements to provide us with adequate liquidity to fund our operations and capital programs. Accordingly, the Company has chosen to preserve liquidity by not devoting capital to its oil and gas properties, while minimizing expenditures for operating, general and administrative expenses. With positive working capital, we will be positioned to capitalize on increases in commodity pricing when such changes occur.

The following table summarizes total current assets, total current liabilities and working capital at year ended December 31, 2016 compared to the year ended December 31, 2015.

		Year Ended December 31, 2016		Year Ended December 31, 2015		Difference
Current Assets	$	1,678,967	$	7,213,213	$	(5,534,246)
Current Liabilities	$	19,754,407	$	4,260,559	$	(15,493,848)
Working Capital (deficit)	$	(18,075,440)	$	2,952,654	$	(21,028,094)

Senior Secured Credit Facility

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

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

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

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

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

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

On April 16, 2013, the Bank increased our borrowing base to $19,500,000.

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

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

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

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

On April 29, 2015, we entered into a Ninth Amendment to the Amended and Restated Credit Agreement. In the Ninth Amendment, the Banks (i) re-determined the Borrowing Base based upon the recent Reserve Report dated January 1, 2015, (ii) imposed affirmative obligations on the Company to use a portion of proceeds received with regard to future sales of securities or certain assets to repay the loan, (iii) consented to non-compliance by the Company with certain terms of the Credit Agreement, (iv) waived certain provisions of the Credit Agreement, and (v) agreed to certain other amendments to the Credit Agreement.

On May 1, 2015, the Borrowers and the Banks entered into a Letter Agreement to clarify that up to $1,000,000 in proceeds from any potential future securities offering will be unencumbered by the Banks' Liens as described in the Credit Agreement through November 1, 2015, and that, until November 1, 2015, such proceeds shall not be subject to certain provisions in the Credit Agreement prohibiting the Company from declaring and paying dividends that may be due and payable to holders of securities issued in such potential offerings or issued prior to the Letter Agreement.

On August 12, 2015, we entered into a Tenth Amendment to the Amended and Restated Credit Agreement. The Tenth Amendment reflects the following changes: (i) allow the Company to sell certain oil assets in Kansas, (ii) allow for approximately $1,300,000 of the proceeds from the sale to be reinvested in Company owned oil and gas projects and (iii) apply not less than $1,500,000 from the proceed of the sale to outstanding loan balances.

On November 13, 2015, the Company entered into a Eleventh Amendment to the Amended and Restated Credit Agreement. The Eleventh Amendment reflects the following changes: (i) waived certain provisions of the Credit Agreement, (ii) suspend certain hedging requirements, and (iii) to make certain other amendments to the Credit Agreement.

Our current borrowing base is $17,925,000, of which we had borrowed $17,925,000 as of December 31, 2016. The interest rate on amounts borrowed under our credit facility during 2016 was approximately 8.7% and for the year ended December 31, 2015, the interest rate on amounts borrowed was approximately 4.3%. This facility expires on October 3, 2018.

On April 1, 2016, the Company informed the Bank that it would cease making the mandatory monthly borrowing base reduction payments and did not make the required April 1, 2016 payment. The Company made its mandatory quarterly interest payments on April 6, 2016, and May 2, 2016. On April 7, 2016 the Company entered into a Forbearance Agreement whereby the Bank agreed to not exercise remedies and rights afforded it under the Amended and Restated Credit Agreement for thirty days. The thirty day period was to be used by the Company to pursue strategic alternatives.

On April 28, 2016 the Bank informed the Company that it would extend the above Forbearance Agreement period to May 31, 2016 upon effecting a principal reduction of $125,000. In addition, the Company will receive an automatic extension to September 15, 2016 upon meeting certain terms and conditions specified by the Bank. On May 31, 2016, the Company and the Bank amended the Forbearance Agreement to extend the forbearance period to August 31, 2016. On July 29, 2016, the Company and the Bank amended the Forbearance Agreement to extend the forbearance period to October 1, 2016.

On October 1, 2016, the Company and the Bank could not reach an agreement to extend the Third Amendment to the Forbearance Agreement. Following this outcome, the Company decided to discontinue payment of interest on its outstanding loan obligations with the Bank. The Company continued to evaluate plans to restructure, amend or refinance existing debt through private options.

On February 10, 2017, the Company, the Bank and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into a Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022, Buyer may acquire the interest in clause (ii) above.

In connection with the LSA, we release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and PWCM Investment Company IC LLC, a Delaware limited liability company and other buyers (collectively, the "successor lender"), entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the “letter agreement”) pursuant to which:

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

    a. convey our oil and gas properties and associated performance and surety bonds in Colorado, Texas, and Nebraska, and

    b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

    c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company’s oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

The Closing is expected to occur on or before May 1, 2017 (the February 10, 2017 letter agreement provided for a Closing on or before April 30, 2017. This was amended to May 1, 2017 in the amendment).

Satisfaction of our cash obligations for the next 12 months

We will not be able to meet our cash obligations for the next 12 months unless the proposed loan forgiveness transaction with our successor lender under out secured credit facility discussed above closes

If the loan forgiveness transaction with the successor lender does not close, our indebtedness under our secured credit facility will remain outstanding and in default, and the secured lender will likely foreclose on all of our assets and we will not be able to continue as a going concern. We will also need to raise additional funds to continue operations and to meet our near term cash obligations after the transaction. We may raise additional funds assets sales and cash flow generated from operations.

Due to the declines in oil prices, the resulting decline in our reserves caused a corresponding reduction to our borrowing base, our continued default of our obligations under the secured credit facility, our issuances of equity securities from our "shelf" registration, our issuance of Series B preferred equity with an anti-dilution protection, and, if the loan restructuring transaction is closed, the reduced size of our business (as discussed above we will only retain the Kansas assets) it will be more difficult in 2017 to use our historical means to meet our cash obligations in the next twelve months.

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 10 full-time employees, two temporary employees and one part-time employee 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. For the year ended December 31, 2016 impairments of $4,506,933, $2,137,663, $800,000 and $588,073 were recorded for the first, second, third quarters and fourth quarters respectively. For the year ended December 31, 2015 impairments of $16,401,376, $11,421,613, $9,720,983 and $11,386,115 were record in the first, second, third and fourth quarters respectively.

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. In 2015 the Company sold its Cherokee project assets located in Kansas for net proceeds of $2,867,305. At the time of the sale the reserve quantities made up approximately 6.7% of total reserve quantities. Accordingly, the net proceeds reduced the carrying value of our oil and gas properties.

Asset Retirement Obligations

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

Share-Based Payments

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

Recent Issued Accounting Standards

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

Effects of Inflation and Pricing

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

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

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Management Responsibility for Financial Information

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

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

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

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

Our Interim Chief Executive Officer, Louis G. Shott., 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, 2016.

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.

On October 3, 2011, we entered into an Amended and Restated Credit Agreement with Texas Capital Bank, and other financial institutions and banks ("Bank") that may become a party to the Credit Agreement from time to time. The facilities provided under the Amended and Restated Credit Agreement was to be used to refinance a prior outstanding revolving loan facility with TCB dated July 3, 2008, and for working capital and general corporate purposes. On August 15, 2014 we entered into an Eighth Amendment to the Amended and Restated Credit Agreement. Among other things the Eighth Amendment extended the maturity of the Agreement by three years to October 3, 2018. On August 12, 2015, we entered into a Tenth Amendment to the Amended and Restated Credit Agreement. Among other things the Tenth Amendment established the requirement of monthly borrowing base reductions commencing September 1, 2015 and continuing on the first of each month thereafter.

On February 10, 2017, the Company, TCP and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into a Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022, Buyer may acquire the interest in clause (ii) above. In connection with the LSA, we release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and PWCM Investment Company IC LLC, a Delaware limited liability company and other buyers (collectively, the "successor lender"), entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the "letter agreement") pursuant to which

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

    a. convey our oil and gas properties in Colorado, Texas, and Nebraska, and

    b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

    c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company's oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

Borrower shall retain all of its existing oil and gas properties located in Kansas, including equipment and tangible personal property related to those oil and gas properties. The Kansas-based assets that the Company will retain generate a majority of the Company's revenue and cash flow from operations. These assets shall secure the remaining $3,300,000 due in 6 months, nine months or a year.

The Closing is expected to occur on or before May 1, 2017.

If we are unable to complete the proposed loan forgiveness transaction with our successor lender, we may need to seek relief under the U.S. Bankruptcy Code. This relief may include: (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets pursuant to section 363(b) of the U.S. Bankruptcy Code and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization (where votes for the plan may be solicited from certain classes of creditors prior to a bankruptcy filing) that we would seek to confirm (or "cram down") despite any classes of creditors who reject or are deemed to have rejected such plan; or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks.

Under certain circumstances, it is also possible that our creditors may file an involuntary petition for bankruptcy against us.

All these factors raise substantial doubt about our ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2017 Annual Stockholder Meeting of Stockholders filed 120 days after December 31, 2016.

ITEM 11. EXECUTIVE COMPENSATION.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2017 Annual Stockholder Meeting of Stockholders filed 120 days after December 31, 2016.

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

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2017 Annual Stockholder Meeting of Stockholders filed 120 days after December 31, 2016.

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

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2017 Annual Stockholder Meeting of Stockholders filed 120 days after December 31, 2016.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information in response to this item is incorporated by reference from the registrant's definitive proxy statement for its 2017 Annual Stockholder Meeting of Stockholders filed 120 days after December 31, 2016.

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

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Consolidated Balance Sheets	F-4
Consolidated Statements of Operations	F-5
Consolidated Statements of Stockholders Equity	F-6
Consolidated Statements of Cash Flows	F-7

2. Financial Statement Schedules

None.

3. Exhibit Index

Exhibit No.	Description
2.1	Agreement and Plan of Merger between Millennium Plastics Corporation and Midwest Energy, Inc. filed on August 16, 2006. (incorporated by reference to Exhibit 2.3 to 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 Appendix C to Schedule 14A filed on June 6, 2013)
3.3	Certificate of Amendment of Articles of Incorporation as filed with the Nevada Secretary of State on May 29, 2014 (incorporated herein by reference as Exhibit 3.1 on Current Report Form 8-K filed on May 29, 2014)
3.4	Certificate of Amendment of Articles of Incorporation (incorporated by reference as Exhibit 3.1 on Current Report Form 8-K filed on May 29, 2014)
3.5	Amended and Restated Certificate of Designation for Series A Preferred Stock (incorporated by reference to Exhibit 4.6 to the Form S-1/A filed on June 3, 2014)
3.6	Certificate of Designation of Preferences, Rights and Limitations of Series B Convertible Preferred Stock (incorporated herein by reference as Exhibit 4.1 on Current Report Form 8-K filed on March 11, 2015)
4.1	Specimen common stock certificate (incorporated by reference to Exhibit 4.3 to the Form S-1/A filed on May 27, 2008)
4.2	Specimen Series A Preferred Stock Certificate (incorporated by reference to Exhibit 4.4 to the Form S-1/A filed on June 3, 2014)
4.3	Specimen Series B Convertible Preferred Stock Certificate (incorporated herein by reference as Exhibit 4.2 on Current Report Form 8-K filed on March 11, 2015)
4.4	Certificate of Designation for Series A Preferred Stock (incorporated by reference to Exhibit 4.1 to the Form 8-K filed on January 6, 2011).
4.5	Form of Warrant to Purchase Common Stock (incorporated herein by reference as Exhibit 4.3 on Current Report Form 8-K filed on March 11, 2015)
4.6	Form of Placement Agent Warrant (incorporated herein by reference as Exhibit 4.4 on Current Report Form 8-K filed on March 11, 2015)
10.1	Form of Officer and Director Indemnification Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on October 16, 2008)
10.2	Amendment 4 to Joint Exploration Agreement effective as of November 6, 2008 between MorMeg, LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.15 to the Form 10-K filed July 14, 2009)
10.3	Amendment 5 to Joint Exploration Agreement effective as of December 31, 2009 between MorMeg LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.15 to the Form 10-Q filed on February 16, 2010)
10.4	Amendment 6 to Joint Exploration Agreement effective as of March 31, 2010 between MorMeg LLC and EnerJex Resources, Inc. (incorporated by reference to Exhibit 10.24 to the Form 10-K filed on July 15, 2010)
10.5	Amended and Restated EnerJex Resources, Inc. Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on October 16, 2008)
10.6	Joint Development Agreement between EnerJex Resources, Inc. and Haas Petroleum, LLC dated December 31, 2010 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on January 27, 2011).
10.7	Joint Operating Agreement between EnerJex Resources, Inc. and Haas Petroleum, LLC and MorMeg, LLC dated December 31, 2010 (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on January 27, 2011).
10.8	Amended and Restated Credit Agreement dated October 3, 2011 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on October 6, 2011).
10.9	Option and Joint Development Agreement by and among Registrant and MorMeg, LLC dated August 2011 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on November 15, 2011).
10.10	First Amendment to Amended and Restated Credit Agreement dated December 14, 2011 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on December 14, 2011).
10.11	Second Amendment to Amended and Restated Credit Agreement dated August 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on November 8, 2012).
10.12	Third Amendment to Amended and Restated Credit Agreement dated November 2, 2012 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on November 8, 2012).
10.13	Amended and Restated Employment Agreement by and among Registrant and Robert G. Watson, Jr. dated December 31, 2012 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed on January 4, 2013).
10.14	Fourth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed on January 30, 2013).
10.15	First Amendment to Amended & Restated Mortgage Security Agreement, Financing Statement and Assignment of Production by and among Working Interest, LLC and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.3 on Form 8-K filed on January 30, 2013).
10.16	Mortgage, Security Agreement, Financing Statement and Assignment of Production and Revenues by and among Working Interest, LLC and Texas Capital Bank dated December 31, 2012 (incorporated herein by reference to Exhibit 10.4 on Form 8-K filed on January 30, 2013).
10.17	2013 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 on Registration Statement on Form S-8 filed on June 12, 2013)
10.18	Fifth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated September 30, 2013 (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed October 1, 2013).
10.19	Sixth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated November 19, 2013 (incorporated by reference to Exhibit 10.37 on Form 10-Q filed May 13, 2014).
10.20	Exchange Agreement between EnerJex Resources, Inc. and holders of Series A preferred stock (incorporated by reference to Exhibit 10.38 on Form S-1/A Amendment No. 2 filed June 3, 2014).

10.21	Seventh Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated May 22, 2014 (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 27, 2014).
10.22	Form of Securities Purchase Agreement dated as of March 11, 2015 (incorporated herein by reference as Exhibit 10.1 on Current Report Form 8-K filed on March 11, 2015)
10.23	Eighth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated August 13, 2014 (incorporated by reference as Exhibit 10.23 on Form 10-K filed March 31, 2015).
10.24	Ninth Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated April 29, 2015 (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 5, 2015).
10.25	Purchase Agreement by and among Registrant and Northland Securities, Inc. dated May 8, 2015 (incorporated by reference as Exhibit 1.1 of Form 8-K filed May 8, 2015.)
10.26	Tenth Amendment to the Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated September 8, 2015 (incorporated by reference to Exhibit 10.26 of Form 10-Q filed November 16, 2015).
10.27	Eleventh Amendment to Amended and Restated Credit Agreement by and among Registrant and Texas Capital Bank, N.A. dated November 16, 2015 (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 16, 2015).
10.28	Forbearance Agreement dated April 4, 2016 (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 3, 2016).
10.29	Third Amendment to Forbearance Agreement dated July 29, 2016 (incorporated by reference to Exhibit 10.1 to Form 8-K filed on August 1, 2016.
10.30	Letter Agreement dated February 10, 2017, by and among Texas Capital Bank, N.A., Iberia Bank, PWCM Investment Company IC LLC, EnerJex Resources, Inc., EnerJex Kansas, Inc., Black Sable Energy, LLC, Black Raven Energy, Inc. and Adena, LLC (incorporated by reference to Exhibit 10.1 on Form 8-K filed February 14, 2017).
10.31	Loan Sale Agreement dated February 10, 2017, by and among Texas Capital Bank, N.A., Iberia Bank, PWCM Investment Company IC LLC, EnerJex Resources, Inc., EnerJex Kansas, Inc., Black Sable Energy, LLC, Black Raven Energy, Inc., and Adena, LLC (incorporated by reference to Exhibit 10.2 on Form 8-K filed February 14, 2017).
10.32	Consulting Agreement dated February 10, 2017, by and between Registrant and Douglas Wright (incorporated by reference to Exhibit 10.3 on Form 8-K filed February 14, 2017).
10.33	Employment Agreement dated February 10, 2017, by and between Registrant and Louis G. Schott (incorporated by reference to Exhibit 10.4 on Form 8-K filed February 14, 2017).
10.34	Separation and General Release Agreement dated February 10, 2017, by and between Registrant and Robert G. Watson, Jr.*
21.1	Subsidiaries*
23.1	Consent of Cobb & Associates, Inc.*
23.2	Cobb & Associates Letter Report dated March 15, 2017*
23.3	Cobb & Associates Letter Report dated February 29, 2016*
24.1	Power of Attorney (included with signatures).*
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002*
31.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
32.2	Certificate of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
101.INS	XBRL Instance Document*
101.SCH	XBRL Taxonomy Extension Schema Document*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document*

* Filed herewith.

SIGNATURES

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

ENERJEX RESOURCES, INC.

By: /s/ Louis G. Schott
Louis G. Schott
Interim Chief Executive Officer

Date: March 31, 2017

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/ Louis G. Schott Louis G. Schott	Interim Chief Executive Officer, (Principal Executive Officer), Secretary	March 31, 2017
/s/ Douglas M. Wright Douglas M. Wright	Chief Financial Officer	March 31, 2017
/s/ Ryan A. Lowe Ryan A. Lowe	Director	March 31, 2017
/s/ Lance W. Helfert Lance Helfert	Director	March 31, 2017
/s/ James G. Miller James G. Miller	Director	March 31, 2017
/s/ Richard E. Menchaca Richard E. Menchaca	Director	March 31, 2017

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Report of Independent Registered Public Accounting Firm

To The Board of Directors and Stockholders of
EnerJex Resources Inc.

We have audited the accompanying consolidated balance sheets of EnerJex Resources Inc. ("The Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, stockholders' deficiency, for the years ended December 31, 2016 and 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatements. 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 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 financial statements referred to above present fairly, in all material respects, the financial position of EnerJex Resources Inc., as of December 31, 2016 and 2015 and the results of its operations, and its cash flows for the years ended December 31, 2016 and 2015 in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company is a going concern. As discussed in Note 2 of the financial statements, the Company plans a significant restructuring which if successful will forgive substantially all of its outstanding debt obligations. Closing of this transaction is scheduled on or before April 30, 2017. Management's plans as to this matters are described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

RBSM, LLP

RBSM, LLP
New York, New York
March 31, 2017

Las Vegas, NV   Kansas City, MO   Houston, TX   New York, NY   Washington DC
Mumbai, India   Athens, Greece   San Francisco, CA   Beijing, China
Member ANTEA INTERNATIONAL with offices worldwide

EnerJex Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2016	December 31, 2015
Assets		
Current Assets:		
Cash unrestricted	$ 128,035	$ 3,101,682
Restricted cash	50,000	-
Accounts receivable	600,255	977,488
Derivative receivable	10,570	2,531,401
Inventory	185,733	144,327
Marketable securities	210,990	210,990
Deposits and prepaid expenses	493,384	247,325
Total current assets	1,678,967	7,213,213
Non-current assets:		
Fixed assets, net of accumulated depreciation of $1,817,711 and $1,658,073	2,077,055	1,995,010
Oil & gas properties using full cost accounting, net of accumulated DD&A of $15,189,716 and $14,935,386	3,437,030	11,706,939
Other non-current assets	798,809	919,239
Total non-current assets	6,312,894	14,621,188
Total assets	$ 7,991,861	$ 21,834,401
Liabilities and Stockholders' (Deficit) Equity		
Current liabilities:		
Accounts payable	$ 294,241	$ 1,142,842
Accrued liabilities	1,535,165	1,131,057
Current portion of long term debt	17,925,000	1,986,660
Total current liabilities	19,754,406	4,260,559
Non-Current Liabilities:		
Asset retirement obligation	3,314,191	3,091,478
Long-term debt	-	16,625,000
Other long-term liabilities	3,401,149	390,937
Total non-current liabilities	6,715,340	20,107,415
Total liabilities	26,469,746	24,367,974
Commitments and Contingencies		
Stockholders' (Deficit) Equity:		
10% Series A Cumulative Redeemable Perpetual Preferred Stock, $.001 par value, 25,000,000 shares authorized; shares issued and outstanding 938,248 at December 31, 2016 and December 31, 2015	938	938
Series B Convertible Preferred stock, $.001 par value, 1,764 shares authorized, issued and outstanding at December 31, 2016 and December 31, 2015	2	2
Common stock, $0.001 par value, 250,000,000 shares authorized; shares issued and outstanding 8,423,936 at December 31, 2016 and December 31, 2015	8,424	8,424
Paid in capital	69,090,613	68,848,944
Accumulated deficit	(87,577,862)	(71,391,881)
Total stockholders' (deficit)	(18,477,885)	(2,533,573
Total liabilities and stockholders' (deficit) equity	$ 7,991,861	$ 21,834,401

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31, 2016	2015
Crude oil revenues	$ 2,390,024	$ 4,525,089
Natural gas revenues	71,703	353,633
Total revenues	2,461,727	4,878,722
Expenses:		
Direct operating costs	2,661,258	4,501,940
Depreciation, depletion and amortization	413,967	1,311,446
Impairment of oil and gas assets	8,032,670	48,930,087
Professional fees	310,471	680,860
Salaries	1,642,593	1,927,552
Administrative expense	539,571	636,459
Total expenses	13,600,530	57,988,344
Loss from operations	(11,138,803)	(53,109,622)
Other income (expense):		
Interest expense	(1,911,906)	(1,293,407)
Gain (loss) on mark to market of derivative contracts	(2,531,401)	(2,194,679
Other income (loss)	2,406,340	4,675,854
Total other income (expense)	(2,036,967)	1,187,768
(Loss) income before provision for income taxes	(13,175,770)	(51,921,854)
Provision for income taxes	-	-
Net (loss)	$ (13,175,770)	$ (51,921,854)
Net (loss)	$ (13,175,770)	$ (51,921,854
Preferred dividends	(3,010,211)	(1,798,274)
Net (loss) attributable to common stockholders	$ (16,185,981)	$ (53,720,128)
Net (loss) per common share basic and diluted	(1.92)	(6.50)
Weighted Average Shares	8,423,936	8,265,716

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc. and Subsidiaries
Consolidated Statement of Stockholders' (Deficit)

	10% Series A Preferred Stock		Series B Preferred Stock		Common Stock		Accumulated Other Comprehensive	Paid In	Retained	Total Stockholders'
	Shares	Amount	Shares	Amount	Shares	Amount	Income	Capital	Deficit	(Deficit)
Balance, January 1, 2015	751,815	752			7,643,114	7,643	(552,589)	63,825,998	(17,280,817)	46,000,987
Dividend received from Oakridge Energy							552,589			552,589
Stock issued for services	3,000	3			17,500	18		23,979		24,000
Stock based compensation								396,124		396,124
Sale of commons stock					763,322	763		824,643		825,506
Sale of series A preferred stock	185,433	1,832						2,014,410		2,014,595
Sale if series B preferred stock			1,764	2				1,763,790		1,763,792
Preferred stock dividends									(2,189,210)	(2,189,210)
Net loss for the year									(51,921,854)	(51,921,854)
Balance, December 31, 2015	938,248	938	1,764	2	8,423,936	8,424	-	68,848,944	(71,391,881)	(2,533,573)
Stock based compensation								241,669		241,669
Preferred stock dividends									(3,010,211)	(3,010,211)
Net loss for the year									(13,175,770)	(13,175,770)
Balance, December 31, 2016	938,248	$ 938	1,764	$ 2	8,423,936	$ 8,424	$ -	$ 69,090,613	$ (87,757,862)	$ (18,477,885)

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Cash flows from operating activities		
Net (loss)	$ (13,175,770)	$ (51,921,854)
Depreciation, depletion and amortization	413,967	1,311,446
Impairment of oil and gas assets	8,032,670	48,930,087
Stock, options and warrants issued for services	241,669	420,103
Accretion of asset retirement obligation	225,480	257,712
Settlement of asset retirement obligations	(2,767)	(2,244)
(Gain) loss on derivatives	2,520,831	2,190,350
Loss on sale of fixed assets	-	13,661
Adjustments to reconcile net (loss) (used in) operating activities:		
Changes in current assets and liabilities		
Accounts receivable	377,233	301,021
Inventory	(41,406)	103,891
Deposits and prepaid expenses	(246,059)	77,014
Accounts payable	(848,601)	(1,899,993)
Accrued liabilities	404,108	70,131
Cash flows used in operating activities	(2,098,645)	(148,675)
Cash flows from investing activities		
Purchase of fixed assets	(241,683)	(7,876)
Oil and gas properties additions	(17,089)	(251,821)
Sale of oil and gas properties	-	2,867,305
Proceeds from sale of fixed assets	-	33,142
Increase in restricted cash	(50,000)	
Dividend received from Oakridge Energy	-	1,360,172
Cash flows (used in) investing activities	(308,772)	4,000,922
Cash flows from financing activities		
Proceeds from sale of stock	-	4,603,812
Repayments of long-term debt	(686,660)	(4,935,595)
Borrowings on long-term debt	-	500,000
Preferred stock dividends paid	-	(1,798,274)
Deferred financing costs	120,430	73,968
Cash flows (used in) financing activities	(566,230)	(1,556,089)
(Decrease) increase in cash and cash equivalents	(2,973,647)	2,296,158
Cash and cash equivalents, beginning	3,101,682	805,524
Cash and cash equivalents, end	$ 128,035	$ 3,101,682
Supplemental disclosures:		
Interest paid	$ 922,072	$ 840,513
Income taxes paid	$ -	$ -
Non-cash investing and financing activities:		
Share-based payments issued for services	$ 241,669	$ 420,103
Preferred dividends payable	$ 3,010,211	$ 390,936

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.

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.

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, (7) valuation of derivative instruments and (8) impairment of oil and gas assets. 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.

Inventory

Inventories are comprised of crude oil held in storage and materials and supplies used in field operations. Crude oil inventories are valued at lower of cost or market, on a first-in, first out basis. Material and supplies are valued at lower of cost or market, based upon specific cost or by using a weighted average cost.

Share-Based Payments

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

Income Taxes

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

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

Uncertain Tax Positions

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

We have no liability for unrecognized tax benefits recorded as of December 31, 2016 and 2015. 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 consolidated statement of operations or consolidated balance sheet as of December 31, 2016. 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, 2016 are the years ended December 31, 2013, 2014 and 2015. Tax years ending prior to 2013 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, can exceeds federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Revenue Recognition

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

Fixed Assets

Property and equipment are recorded at cost.

At December 31, 2016, Fixed Assets consisted of vehicles $355,886, furniture and equipment of $795,563, building and leasehold improvements of $23,069 and gathering and compression systems of $2,720,247, as well as accumulated depreciation of vehicles of $336,083, accumulated depreciation of furniture and fixtures of $532,190, accumulated depreciation of building and leasehold improvements of $17,515 and accumulated depreciation of gathering and compression systems of $931,923.

At December 31, 2015, Fixed Assets consisted of vehicles of $354,887, furniture and equipment of $552,288, building and leasehold improvements of $23,069 and gathering and compression systems of $2,722,839 as well as accumulated depreciation of vehicles $328,659, accumulated depreciation of furniture and fixtures of $478,578, accumulated depreciation of building and leasehold improvements of $13,342 and accumulated depreciation of gathering and compression systems of $837,494.

Depreciation is determined by the use of the straight-line method of accounting 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 utilizing the straight-line method of amortization over the estimated life of the debt.

Oil & Gas Properties and Long-Lived Assets

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.

Impairment of long-lived assets is recorded when indications of impairment are present. Impairment is indicated when 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 measured based on an estimate of future discounted cash flows.

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. For the year ended December 31, 2015 impairment charges of $48,930,087 were record. For the year ended December 31, 2016 impairment charges of $8,032,670 were recorded.

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. In 2015 the Company sold its Cherokee project assets located in Eastern Kansas for net proceeds of $2,867,305. At the time of the sale the reserve quantities made up approximately 6.7% of total reserve quantities. Accordingly, the net proceeds reduced the carrying value of our oil and gas properties.

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, 2016, and 2015 we sold our produced crude oil to ARM Energy Management, LLC, Coffeyville Resources Inc., and Sunoco Logistics Inc. on a month-to-month basis and we sold our produced natural gas to United Energy Trading and Western Operating Company.

Marketable Securities Available for Sale

The Company classifies its marketable equity securities as available-for-sale and they are carried at fair market value, with the unrealized gains and losses included in accumulated other comprehensive income and reported in stockholders' equity. The difference between historical cost and market totaled $552,589 for the year ended December 31, 2014. For the year ended December 31, 2015 the Company received a dividend of $1,360,172. This receipt of cash was first applied to the other comprehensive loss reported in stockholders' equity and then to the carrying value of the security reported in current assets. This resulted in a new carrying value of $210,990 for this security. The Company expects future distributions and estimates that the sum of future distributions to be in excess of the remaining book value.

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, 2016 and 2015, diluted net loss per share did not include the effect of 298,664 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 - Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates the realization of assets and liquidation of liabilities in the normal course of business. The Company had an accumulated deficit at December 31, 2016 of $87,577,862. Also, net loss was $13,175,770 and cash used in operations was $2,098,645 for the year ended December 31, 2016. The ability of the Company to continue as a going concern is dependent upon its ability to successfully accomplish the plans described below to restructure, amend or refinance debt and secure financing and attain profitable operations. The accompanying consolidated financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

On October 3, 2011, the Company, entered into an Amended and Restated Credit Agreement with Texas Capital Bank, and other financial institutions and banks ("TCB" or "Bank") that may become a party to the Credit Agreement from time to time. The facilities provided under the Amended and Restated Credit Agreement was to be used to refinance a prior outstanding revolving loan facility with TCB dated July 3, 2008, and for working capital and general corporate purposes. On August 15, 2014 the Company entered into an Eighth Amendment to the Amended and Restated Credit Agreement. Among other things the Eighth Amendment extended the maturity of the Agreement by three years to October 3, 2018. On August 12, 2015, the Company entered into a Tenth Amendment to the Amended and Restated Credit Agreement. Among other things the Tenth Amendment established the requirement of monthly borrowing base reductions commencing September 1, 2015 and continuing on the first of each month thereafter. On November 13, 2015, the Company entered into a Eleventh Amendment to the Amended and Restated Credit Agreement. The Eleventh Amendment reflects the following changes: (i) waived certain provisions of the Credit Agreement, (ii) suspend certain hedging requirements, and (iii) to make certain other amendments to the Credit Agreement.

On April 1, 2016 the Company informed the Bank that it would cease making the mandatory monthly borrowing base reduction payments and did not make the required April 1, 2016 payment. The Company made its mandatory quarterly interest payment on April 6, 2016 and on April 7, 2016 entered into a Forbearance Agreement whereby the Bank agreed to not exercise remedies and rights afforded it under the Amended and Restated Credit Agreement for thirty days. On May 31, 2016, the Company and the Bank amended to the Forbearance Agreement to extend the forbearance period to August 31, 2016. On July 29, 2016, the Company and the Bank entered into a Third Forbearance Agreement which extended the forbearance period to October 1, 2016. Upon the expiration of the Third Forbearance agreement, the Company did not enter into a fourth Forbearance Agreement. Also, at that time the Company discontinued payment of interest on its outstanding loan obligations with the Bank.

Throughout 2016, the Company evaluated plans to restructure, amend or refinance existing debt through private options. On February 14, 2017 the Company announced that a group of investors unrelated the Company has purchased from EnerJex's secured bank lender all rights to the Company's secured indebtedness, and that EnerJex has executed with the purchasing investor group a definitive written agreement for the discharge of the Company's secured indebtedness.

On February 10, 2017, the Company, TCB and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into a Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022, Buyer may acquire the interest in clause (ii) above. In connection with the LSA, the Company release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and successor lender entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the "letter agreement") pursuant to which:

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

   a. convey our oil and gas properties and associated performance and surety bonds in Colorado, Texas, and Nebraska, and

   b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

   c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company's oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

The Closing is expected to occur on or before May 1, 2017 (the February 10, 2017 letter agreement provided for a Closing on or before April 30, 2017. This was amended to May 1, 2017 in the amendment). See footnote number 13 of these financial statements for additional information.

Note 3 - Equity Transactions

Stock transactions in fiscal year ended December 31, 2016

There were no equity transactions for the year ended December 31, 2016.

Stock transactions in fiscal year ended December 31, 2015

On March 13, 2015, the Company issued in a registered offering 763,322 registered shares of its common stock together with 1,242.17099 shares of its newly designated Series B Convertible Preferred Stock (the "Preferred Stock") convertible into 709,812 shares of common stock. We also issued in an unregistered offering, 521.62076 shares of Preferred Stock convertible into 298,069 shares of common stock, and warrants to purchase 1,771,428 shares of its common stock. The shareholder's ability to convert a portion of the Preferred Stock and to exercise the warrant are restricted: (i) prior to the Company obtaining approval of the offering by its shareholders, which we expect to obtain before May 31, 2015, and (ii) pursuant to customary "blocker" provisions restricting the investor's ownership to 9.99% of our outstanding common stock.

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

On May 13, 2015, the Company sold 183,433 shares of its 10% Series A Cumulative Redeemable Perpetual Preferred Stock at $12.50 per share for gross proceeds of approximately $2.3 million. The Company intends to use the net proceeds of this offering for general corporate purposes, including capital expenditures, working capital, preferred stock dividends, and repayment of outstanding borrowings under its senior credit facility.

The offering was made pursuant to a registration statement on Form S-3 (File No. 333-199030) previously filed and declared effective by the U.S. Securities and Exchange Commission (SEC).

Option transactions

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

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

Stock Incentive Plan

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

On December 31, 2010 we granted 60,000 options that vest ratably over a 48 month period and are exercisable at $6.00 per share to an Officer of the company. The term of the options is 5 years. The fair value of the options as calculated using the Black-Scholes model was $307,751. The amount recognized as expense for the year ended December 31, 2015 and 2016 was zero.

2013 Stock Incentive Plan

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

In 2016 no options were granted to any employees or directors.

In 2015, we granted 67,332 options to employees and directors. Fifty percent of these options vest one year after the date of the grant. The remaining options vest ratably each month over a two year period. The fair value of the option on the date of the grant calculated using the Black-Scholes model was $295,932 using the following weighted average assumptions: exercise price of $9.85 per share; common stock price of ranging from $.30 to $2.00 per share; volatility ranging from 70% to 72%; term of three years; dividend yield of 0%; interest rate of 1.41%.

We expensed $241,669 and $420,103 for the years ended December 31, 2016 and December 31, 2015 respectively for options granted.

A summary of stock options is as follows:

	Options	Weighted Ave. Exercise Price	Warrants	Weighted Ave. Exercise Price
Outstanding January 1, 2015	231,332	$ 9.33		$
Granted	67,332	9.85	1,904,286	2.75
Cancelled	(10,333)	(10.50)		
Exercised	-	-	-	-
Outstanding December 31, 2015	288,331	$ 10.17	1,904,286	$ 2.75
Granted	-	-	-	-
Cancelled	(80,667)	(7.15)	-	-
Exercised			-	-
Outstanding December 31, 2016	207,664	$ 9.69	1,904,286	$ 2.75

The number of options that were vested at December 31, 2016 was 195,172. The number of options that were not vested at December 31, 2016 was 12,493.

Note 4 - 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, 2015	$ 2,906,093
Liabilities incurred during the period	-
Release of liabilities associated with the sale of oil properties	(70,083)
Liabilities settled during the year	(2,244)
Accretion	257,712
Asset retirement obligations, December 31, 2015	$ 3,091,478
Liabilities incurred during the period	-
Liabilities settled during the year	(2,767)
Accretion	225,480
Asset retirement obligations, December 31, 2016	$ 3,314,191

Note 5 - Long-Term Debt

Senior Secured Credit Facility

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

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

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

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

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

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

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

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

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

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

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

On April 29, 2015, we entered into a Ninth Amendment to the Amended and Restated Credit Agreement. In the Ninth Amendment, the Banks (i) re-determined the Borrowing Base based upon the recent Reserve Report dated January 1, 2015, (ii) imposed affirmative obligations on the Company to use a portion of proceeds received with regard to future sales of securities or certain assets to repay the loan, (iii) consented to non-compliance by the Company with certain terms of the Credit Agreement, (iv) waived certain provisions of the Credit Agreement, and (v) agreed to certain other amendments to the Credit Agreement.

On May 1, 2015, the Borrowers and the Banks entered into a Letter Agreement to clarify that up to $1,000,000 in proceeds from any potential future securities offering will be unencumbered by the Banks' Liens as described in the Credit Agreement through November 1, 2015, and that, until November 1, 2015, such proceeds shall not be subject to certain provisions in the Credit Agreement prohibiting the Company from declaring and paying dividends that may be due and payable to holders of securities issued in such potential offerings or issued prior to the Letter Agreement.

On August 12, 2015, we entered into a Tenth Amendment to the Amended and Restated Credit Agreement. The Tenth Amendment reflects the following changes: (i) allow the Company to sell certain oil assets in Kansas, (ii) allow for approximately $1,300,000 of the proceeds from the sale to be reinvested in Company owned oil and gas projects and (iii) apply not less than $1,500,000 from the proceed of the sale to outstanding loan balances.

On November 13, 2015, the Company entered into a Eleventh Amendment to the Amended and Restated Credit Agreement. The Eleventh Amendment reflects the following changes: (i) waived certain provisions of the Credit Agreement, (ii) suspend certain hedging requirements, and (iii) to make certain other amendments to the Credit Agreement.

On April 1, 2016 the Company informed the Bank that it would cease making the mandatory monthly borrowing base reduction payments and did not make the required April 1, 2016 payment. The Company made its mandatory quarterly interest payment on April 6, 2016 and on April 7, 2016 entered into a Forbearance Agreement whereby the Bank agreed to not exercise remedies and rights afforded it under the Amended and Restated Credit Agreement for thirty days. On May 31, 2016, the Company and the Bank amended the Forbearance Agreement to extend the forbearance period to August 31, 2016. On July 29, 2016, the Company and the Bank entered into a Third Forbearance Agreement which extended the forbearance period to October 1, 2016. Upon the expiration of the Third Forbearance agreement, the Company did not enter into a fourth Forbearance Agreement. Also, at that time the Company discontinued payment of interest on its outstanding loan obligations with the Bank.

On February 10, 2017, Borrowers, TCB and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into that certain Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to the five (5) years of February 10, 2017, Buyer may acquire the interest in clause (ii) above. In connection with the LSA, Borrowers release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

On February 10, 2017, the Company, TCB and IberiaBank (collectively, "Sellers"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, "Buyers") entered into a Loan Sale Agreement ("LSA"), pursuant to which Seller sold to Buyers, and Buyers purchased from Sellers, all of Sellers' right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a Synthetic Equity Interest equal to 10% of the Proceeds, after Buyer's realization of 150% return on the Cash Purchase Price within five (5) years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022, Buyer may acquire the interest in clause (ii) above. In connection with the LSA, the Company release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including Buyers, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and successor lender entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the "letter agreement") pursuant to which:

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

    a. convey our oil and gas properties and associated performance and surety bonds in Colorado, Texas, and Nebraska, and

    b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

    c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company's oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

The Closing is expected to occur on or before May 1, 2017 (the February 10, 2017 letter agreement provided for a Closing on or before April 30, 2017. This was amended to May 1, 2017 in the amendment).

Note 6 - Commitments and Contingencies

Rent expense for the years ended December 31, 2016 and 2015 was approximately $148,000 and $149,000 respectively. Future non-cancellable minimum lease payments are approximately, $145,000 for 2017, $91,000 for 2018 and $77,000 for 2019.

As of December 31, 2016, 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.

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, 2016, we have no reserve for environmental remediation and are not aware of any environmental claims.

On September 23, 2016 the Company, American Standard Energy Corporation, Baylor Operating LLC, Bernard Given and Loeb & Loeb LLP were sued by Geronimo Holdings Corporation and Randal Capps in the 143rd Judicial District Court located in Pecos, Texas. The suit among other things, seeks damages for an alleged unlawful sale of properties in Crockett County Texas and for alleged unpaid royalties. The Company believes the suit is without merit and will vigorously defend itself. The Company has faith that it will prevail and at December 31, 2016 no reserve for potential losses arising from this matter has been recorded. Additionally under its agreement with Baylor Operating LLC, Baylor has agreed to indemnify and defend the Company against all lawsuits and claims including this one.

On April 26, 2016 C&F Ranch, LLC sued the Company in Allen County Kansas for alleged breach of contract related to the rental of certain lands located on the C&F Ranch. The Company believes that has paid all rents owe to C&F Ranch LLC and will vigorously defend itself. The Company has faith that it will prevail and at December 31, 2016 no reserve for potential losses arising from this matter has been recorded.

Note 7 - Income Taxes

There was no current or deferred income tax expense (benefit) for the years ended December 31, 2016 and December 31, 2015.

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

	Year Ended December 31, 2016	2015
Statutory tax rate	35.00%	35.00%
State tax rate, net of federal tax	1.78%	1.90%
Other permanent items	0.00%	0.00%
Change in valuation allowance	(36.78)%	(36.90)%
Effective tax rate	(0.00%	0.00%

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

	Year Ended December 31, 2016	2015
Non-current deferred tax asset:		
Oil and gas costs and long-lived assets	$ 11,500,697	$ 14,513,571
Derivative instruments	-	934,340
Net operating loss carry-forward	35,815,113	29,532,954
Valuation allowance	(47,315,809)	(44,980,865)
Net deferred tax asset (liability)	$ -	$ -

At December 31, 2016, we have a net operating loss carry forward of approximately $88 million expiring in 2021-2037 that is subject to certain limitations on an annual basis. A valuation allowance has been established against net operating losses where it is more likely than not that such losses will expire before they are utilized.

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

Note 8 - 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, 2016.

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
Marketable securities	$ -	$ -	$ 210,990

Note 9 - Derivative Instruments

We enter into 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, allowed 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 applied only to a portion of our production.

We had an Inter-creditor 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 were not required to post additional collateral, including cash.

At December 31, 2016 all derivative contracts had expired.

For years ended December 31, 2016 and 2015, the fair value of the Company's derivative contracts were reflected in current assets on the balance sheet. We recorded a loss related to the mark to market our derivative contracts for the year ended December 31, 2016 and 2015 of $2,531,401 and $2,194,679 respectively.

Note 10 - Net Income Per Common Share

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

Note 11 - Impairment of Oil and Gas Properties

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company's costs are included in one cost center because all of the Company's operations are located in the United States. The Company's ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of December 31, 2016, which were based on a West Texas Intermediate oil price of $42.75 per Bbl and a Henry Hub natural gas price of $2.49 per MMBtu (adjusted for basis and quality differentials), respectively. The trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of September 30, 2016, was based on a West Texas Intermediate oil price of $41.97 per Bbl and a Henry Hub natural gas price of $2.39 per MMBtu (adjusted for basis and quality differentials), respectively. The twelve-month, unweighted-average first-day-of-the –month price as of June 30, 2016 was $42.46 per Bbl and $2.63per MMBtu The twelve-month, unweighted-average first-day-of-the –month price as of March 31, 2016 was $45.16 per Bbl and $2.40 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount was less than the net capitalized cost of oil and natural gas properties as of December 31, 2016, and as a result, a pre-tax write-down of $588,073 was recorded. Utilizing these prices, the calculated ceiling amount was less than the net capitalized cost of oil and natural gas properties as of September 30, 2016, and as a result, a pre-tax write-down of approximately $800,000 was recorded. At June 30, 2016 the calculated ceiling amount was less than net capitalized cost of oil and natural gas properties resulted in a pre-tax write-down of $2.1 million. At March 31, 2016 the calculated ceiling amount was less than net capitalized cost of oil and natural gas properties resulted in a pre-tax write-down of $4.5 million. For the year ended December 31, 2015 and 2016 the Company recorded and impairment charges of $48,930,087 and $8,032,670 respectively. Additional material write-downs of the Company's oil and gas properties could occur in subsequent quarters in the event that oil and natural gas prices remain at current depressed levels, or if the Company experiences significant downward adjustments to its estimated proved reserves.

Note 12 - Other Income

The following table depicts the components of other income for the years ended December 31, 2016 and December 31, 2015:

	Year ended December 31, 2016	Year ended December 31, 2015
Realized gain (loss) clearing of derivative contracts	$ 2,382,184	$ 4,662,012
Loss on sale of fixed assets	-	(13,661)
Miscellaneous income	24,124	27,105
Interest income	32	398
Other Income	$ 2,406,340	$ 4,675,854

Note 13 - Subsequent Events

Loan Sale Agreement

On February 10, 2017, the Company, TCB and Iberia Bank (collectively, the "Bank"), and PWCM Investment Company IC LLC, and certain financial institutions (collectively, the "successor lender") entered into a loan sale agreement pursuant to which theBank sold to successor lender the Bank's right, title and interest in, to and under the Credit Agreement and Loan Documents, in exchange for (i) a cash payment of $5,000,000 (the "Cash Purchase Price"), (ii) a synthetic equity interest equal to 10% of the proceeds, after successor lender's realization of 150% return on the Cash Purchase Price within 5 years of the Closing Date, with payment being distributed 65.78947368% to TCB and 34.21052632% to IberiaBank, and (iii) at any time prior to February 10, 2022,, Successor Lender may acquire the synthetic interest in clause (ii) above. In connection with the LSA, we release Sellers and its successors as holders of the rights under the Credit Agreement and Loan Documents, including successor lender, from any and all claims under the Credit Agreement and Loan Documents.

Also on February 10, 2017, the Company and its subsidiaries, and successor lender entered into a binding letter agreement dated February 10, 2017, which was subsequently amended on March 30, 2017 (as amended, the "letter agreement") pursuant to which:

1. the successor lender would agree to forgive our existing secured loan in the approximate principal amount of $17,295,000, and in exchange enter into a secured promissory note (which we refer to as the "restated secured note") in the original principal amount of $4,500,000.

2. we would:

   a. convey our oil and gas properties in Colorado, Texas, and Nebraska, and

   b. all of our shares of Oakridge Energy, Inc. (together, the "conveyed oil and gas assets"); and

   c. retain our assets in Kansas and continue as a going concern. The Kansas assets currently provide most of our current operating revenue.

The restated secured note shall:

a. be secured by a first-priority lien in the Company's oil and gas producing assets situated in the State of Kansas,

b. evidence accrued interest on the $4,500,000 principal balance at a rate of 16% per annum,

c. bear interest from and after May 1, 2017, at a rate of 16.0% per annum,

d. be pre-payable in full at a discount at any time during the term of the restated secured note upon EnerJex's paying $3,300,000 to successor lender, and

e. mature and be due and payable in full on November 1, 2017.

We will have 2 options to extend the maturity date of the restated secured note by 90 days each upon payment of an extension fee of $100,000, which shall be applied against the principal balance of the note.

So long as we repay the $3,300,000 in indebtedness on or prior to the maturity date, as extended, all other amounts payable under the restated secured note shall be forgiven.

The Closing is to occur on or before May 1, 2017.

Management Changes

On February 10, 2017, EnerJex Resources, Inc. and Mr. Robert G. Watson, Jr. CEO entered into a Separation Agreement and Mr. Watson resigned from the Company. Among other things, Mr. Watson agreed to provide consulting services as needed but otherwise has been unemployed since his resignation. On December 7, 2016, prior to his resignation, Mr. Watson recused himself from all Board of Director meetings and has not participated in any Board meetings or discussions since that date. Additionally, on February 10, 2017, Mr. Douglas M. Wright the Chief Financial Officer of the Company, resigned from EnerJex Resources, Inc. Since that date Mr. Wright has not been an officer of the Company. Subsequent to his resignation, he entered into an agreement with the Company to provide, among other things, consulting services for the preparation of the Company's 2016 10-K. The Consulting Services Agreement may be terminated by either party with 30 days written notification.

Note 14 - 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, 2016	Year Ended December 31, 2015
Production revenues	$ 2,461,727	$ 4,878,722
Production costs	(2,661,258)	(4,501,940)
Depletion and depreciation	(254,329)	(1,108,039)
Income tax	158,851	255,940
Results of operations for producing activities	$ (295,009)	$ (475,317)

Capitalized costs

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Properties subject to amortization	$ 18,626,746	$ 26,642,325
Accumulated depletion	(15,189,716)	(14,935,386)
Net capitalized costs	$ 3,437,030	$ 11,706,939

Cost incurred in property acquisition, exploration and development activities

	Year Ended December 31, 2016	Year Ended December 31, 2015
Acquisition of properties	$ 14,399	$ 85,895
Exploration costs	-	-
Development costs	2,690	165,926
Net capitalized costs	$ 17,089	$ 251,821

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 Cobb & Associates, Inc. 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.

	December 31, 2016			December 31, 2015		
Proved Reserves	Total Proved Developed	Proved Undeveloped	Total Proved	Total Proved Developed	Proved Undeveloped	Total Proved
Beginning						
Crude Oil BBL's	1,287,028	202,884	1,489,912	2,214,038	740,700	2,954,738
Natural Gas Liquids BBL's	47,345	-	47,345	89,250	-	89,250
Natural Gas MCF's	3,195,895	3,029,514	6,225,409	4,469,845	3,667,314	8,137,159
Oil Equivalents BOE's	1,867,041	707,819	2,574,860	3,048,261	1,351,919	4,400,180
Revisions of previous estimates						
Crude Oil BBL's	(898,880)	-	(898,880)	(629,480)	(522,070)	(1,151,550)
Natural Gas Liquids BBL's	(3,670)	-	(3,670)	(35,860)	-	(35,860)
Natural Gas MCF's	(108,849)	100	(108,849)	(1,085,542)	(637,800)	(1,723,342)
Oil Equivalents BOE's	(920,691)	100	(920,592)	(846,264)	(628,370)	(1,474,634)
Sales of minerals in place						
Crude Oil BBL's	-	-	-	(201,286)	(15,746)	(217,032)
Production						
Crude Oil BBL's	(58,123)	-	(58,123)	(96,244)	-	(96,244)
Natural Gas Liquids BBL's	(528)	-	(528)	(6,045)	-	(6,045)
Natural Gas MCF's	(47,554)	-	(47,554)	(188,408)	-	(188,408)
Oil Equivalents BOE's	(66,578)	-	(66,578)	(133,690)	-	(133,690)
Ending						
Crude Oil BBL's	330,025	202,884	532,909	1,287,028	202,884	1,489,912
Natural Gas Liquids BBL's	43,237	-	43,237	47,345	-	47,345
Natural Gas MCF's	3,039,673	3,029,614	6,069,287	3,195,895	3,029,514	6,225,409
Oil Equivalents BOE's	879,874	707,820	1,587,690	1,867,041	707,819	2,574,860

Proved developed reserves at December 31, 2015 consisted of approximately 71% oil and 29% natural gas and totaled 1,851.9 MBOEs. Proved developed reserves for December 31, 2016 consisted of approximately 42% oil and 58% natural gas and totaled 879.8 MBOEs. Proved undeveloped reserves for December 31, 2015 were 707.8 MBOEs. Proved undeveloped reserves at December 31, 2016 were 707.8 MBOEs.

The Company annually reviews its proved undeveloped reserves to ensure an appropriate plan for development exists. The Company books proved undeveloped reserves only if it plans to convert these reserves to proved developed producing reserves within five years from the date they were first booked. At December 31, 2016 proved undeveloped reserves were approximately 707.8 MBOE's. The Company plans to develop all the remaining location that comprise the 707.8 MBOE of proved undeveloped reserves within five years. However, the decision to deploy capital and the timing of those expenditures is contingent on many different factors. The Company estimates capital expenditures of approximately $4.3 million will be sufficient to develop these reserves. The development plans assume a continued improvement in commodity pricing and general market conditions within the oil and gas industry.

The calculation of proved undeveloped reserves requires the Company to make predictions regarding future acquisitions and discoveries and the impact they may have on the Company's overall development plan of properties it currently owns. The development plan is revised to reflect changes in the oil and gas industry, including changing markets and prices, and new investment opportunities, and such revisions will result in changes to our proved undeveloped reserves. Consequently, the exact timing of capital expenditures will be heavily dependent upon the Company's interpretation of market opportunities which are deeply influenced by projections of future commodity prices. Each year we will review our five year development plan to maximize the value of our investment in oil and gas assets and in turn maximize shareholder value. At December 31, 2016 we believe the following best characterizes our development plan.

	Estimated Conversion of Proved Undeveloped Reserves	
	CAPEX ($MM)	MBOE's
2017	-	-
2018	2,194.2	50.4
2019	1,664.0	126.2
2020	182.0	232.9
2021	288.0	298.3

For the year ended December 31, 2016 proved reserves decreased 987.1 MBOEs of which production accounted for 66.6 MBOEs or 6.7% of the decrease. The remaining decrease of 920.6 MBOEs, was due primarily to decreases in commodity prices. Crude oil prices decreased $3.49 or 8% and natural gas prices declined 20% or $.37. Diminished commodity pricing triggered negative revisions of 898.9 MBOEs of crude oil classified as proved developed producing. Natural gas liquids decreased pricing resulted in decreases of 3.6 MBOEs to the proved developed producing category. Reduced natural gas prices also reduced amounts classified as proved developed producing by 108.6 MMCF's. In 2016 there were no material transfers from the proved undeveloped category of 6 reserves to the proved developed category

For the year ended December 31, 2015 proved reserves decreased 1,825.3 MBOEs of which production accounted for 133.7 MBOEs or 7.3% of the decrease. The remaining decrease of 1,691.6 MBOEs, was due primarily to decreases in commodity prices. Crude oil prices decreased $40.00 or 46.1% and natural gas prices declined 42.2% or $1.37. Diminished commodity pricing triggered negative revisions of 586.6 MBOEs of crude oil classified as proved developed producing, negative revisions of 42.9 MBOEs of crude oil classified as proved developed non-producing and negative revisions of 522.1 of MBOEs of crude oil classified as proved undeveloped reserves. Natural gas liquids decreased pricing resulted in decreases of 65.6 MBOEs to the proved developed producing category. Reduced natural gas prices also reduced amounts classified as proved developed producing by 1,347.9 MMCF's as well as natural gas reserves classified as proved undeveloped by 637.8 MCF. These decreases were partially offset by increases to natural gas liquid reserves classified as proved developed non-producing of 29.7 MBOE and 262.4 MMCF of natural gas reserves classified as proved developed non-producing. In 2015 there were no material transfers from the proved undeveloped category of reserves to the proved developed category.

In 2016 the Company invested approximately $17,100 in its oil and gas properties. These reduced expenditures were in response to extremely low commodity prices. The Company has approximately $1.7 million of current asset on hand and important infrastructure in Colorado completed which will facilitate the exploitation and development of proved undeveloped reserves over the next five years. At year end the Company's review of proved undeveloped reserves revealed challenges but the Company maintains its belief that reserves will be developed within five years of their initial recording as a proved undeveloped reserve. In addition it believes it has the financial wherewithal to develop all it's proved undeveloped reserves within the five year time frames required; utilizing its balance sheet, to borrow funds as needed. Additionally, the Company believes it has the ability to joint venture any of its assets.

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, 2016	Year Ended December 31, 2015
Future production revenue	$ 30,085,550	$ 74,087,130
Future production costs	(15,278,990)	(46,015,320)
Future development costs	(4,703,230)	(5,901,660)
Future cash flows before income tax	10,103,330	22,170,150
Future income taxes	-	-
Future net cash flows	10,103,330	22,170,150
10% annual discount for estimating of future cash flows	(6,666,300)	(13,400,180)
Standardized measure of discounted net cash flows	$ 3,437,030	$ 8,769,970

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, 2016	Year Ended December 31, 2015
Balance beginning of year	$ 8,769,970	$ 62,703,851
Sales, net of production costs	199,531	(491,055)
Net change in pricing and production costs	(2,012,883)	(51,184,718)
Net change in future estimated development costs	(1,198,430)	7,834,840
Purchase of minerals in place	-	-
Extensions and discoveries	-	-
Sale of minerals in place	-	(2,746,550)
Revisions	(4,538,106)	(8,448,569)
Accretion of discount	2,217,015	16,770,190
Change in income tax		(15,668,019)
Balance end of year	$ 3,437,030	$ 8,769,970