SECURITIES & EXCHANGE COMMISSION EDGAR FILING

Yuma Energy, Inc.

Form: 10-K

Date Filed: 2015-03-30

Corporate Issuer CIK:	81318
Symbol:	YUMA

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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2014

❑ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: **001-32989**

YUMA ENERGY, INC.
(Exact name of registrant as specified in its charter)

CALIFORNIA	**94-0787340**
(State or other jurisdiction of incorporation or organization)	*(IRS Employer Identification No.)*

1177 West Loop South, Suite 1825 Houston, Texas	**77027**
(Address of principal executive offices)	*(Zip Code)*

(713) 968-7000
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value per share	**NYSE MKT**
9.25% Series A Cumulative Redeemable Preferred Stock	**NYSE MKT**

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

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

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

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

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

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

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

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

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

The aggregate market value on June 30, 2014, (the last business day of the registrant's most recently completed second fiscal quarter) of the voting shares held by non-affiliates was approximately $15,171,528 based on the closing sales price of the registrant's common stock on the NYSE MKT on such date

At March 26, 2015, 69,125,624 shares of the Registrant's common stock, no par value, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2015 annual meeting of shareholders which will be filed no later than 120 days after December 31, 2014.

TABLE OF CONTENTS

Cautionary Statement Regarding Forward-Looking Statements

Certain statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts contained in this report are forward-looking statements. These forward-looking statements can generally be identified by the use of words such as "may," "will," "could," "should," "project," "intends," "plans," "pursue," "target," "continue," "believes," "anticipates," "expects," "estimates," "predicts," or "potential," the negative of such terms or variations thereon, or other comparable terminology. Statements that describe our future plans, strategies, intentions, expectations, objectives, goals or prospects are also forward-looking statements. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- volatility and weakness in commodity prices for oil and natural gas and the effect of prices set or influenced by action of the Organization of the Petroleum Exporting countries ("OPEC");
- our ability to successfully integrate acquired oil and natural gas businesses and operations;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and will divert management's time and energy, which could have an adverse effect on our financial position, results of operations, or cash flows;
- risks in connection with potential acquisitions and the integration of significant acquisitions;
- we may incur more debt; higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;
- our oil and natural gas assets are concentrated in a relatively small number of properties;
- access to adequate gathering systems, processing facilities, transportation take-away capacity to move our production to market and marketing outlets to sell our production at market prices, which is necessary to fully execute our capital program;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fully develop our undeveloped acreage positions;
- our ability to replace our oil and natural gas reserves;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the potential for production decline rates for our wells to be greater than we expect;
- our ability to retain key members of senior management and key technical employees;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;

- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);

- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;

- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as Africa, the Middle East, and armed conflict or acts of terrorism or sabotage;

- other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;

- the insurance coverage maintained by us may not adequately cover all losses that may be sustained in connection with our business activities;

- title to the properties in which we have an interest may be impaired by title defects;

- management's ability to execute our plans to meet our goals;

- the cost and availability of goods and services, such as drilling rigs; and

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

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and this annual report on Form 10-K:

2-D Seismic. Geophysical data that depicts the subsurface strata in two dimensions.

3-D Seismic. Advanced technology method of detecting accumulations of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

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

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or *well*. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or *gross wells*. The total acres or wells, as the case may be, in which a working interest is owned.

HH. Henry Hub natural gas price index.

HLS. Heavy Louisiana Sweet oil price index.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

LLS. Light Louisiana Sweet oil price index.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMbtu. One million British Thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

Net revenue interest. An owner’s share of petroleum after satisfaction of all royalty and other non-cost bearing interests.

Net acres or *net wells*. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids.

NYMEX. The New York Mercantile Exchange.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or natural gas well or lease.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH"), as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil ("HKO"), elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves or *PUD*. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

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

Spot market price. The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

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

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate oil price index, light sweet crude oil delivered to Cushing, Oklahoma, the benchmark for crude oil in the United States.

PART I

Item 1. Business.

Overview

Unless the context otherwise requires, all references in this annual report to the "Company," "Yuma," "our," "us," and "we" refer to Yuma Energy, Inc. (formerly known as Pyramid Oil Company) and its subsidiaries, as a common entity. Unless otherwise noted, all information in this annual report relating to oil, natural gas and natural gas liquids reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent reserve engineers and are net to our interest. We have included certain technical terms important to an understanding of our business under the Glossary of Selected Oil and Natural Gas Terms section above. Throughout this annual report we make statements that may be classified as "forward-looking." Please refer to the Cautionary Statement Regarding Forward-Looking Statements section above for an explanation of these types of statements.

Yuma Energy, Inc. is a U.S.-based oil and gas company focused on the exploration for, and development of, conventional and unconventional oil and natural gas properties, primarily through the use of 3-D seismic surveys, in the U.S. Gulf Coast and California. We were incorporated in California on October 7, 1909. We have employed a 3-D seismic-based strategy to build a multi-year inventory of development and exploration prospects. Our current operations are focused on onshore central Louisiana, where we are targeting the Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex and Hackberry formations. In addition, we have a non-operated position in the Bakken Shale in North Dakota and operated positions in Kern and Santa Barbara Counties in California. As a result of the merger between Yuma Energy, Inc., a Delaware corporation ("Yuma Co."), and Pyramid Oil Company, the Company underwent a substantial change in ownership, management, assets and business strategy, all effective as of September 10, 2014. Our common stock is traded on the NYSE MKT under the trading symbol "YUMA." Our Series A Preferred Stock is traded on the NYSE MKT under the trading symbol "YUMAprA."

Business Strategy

Our business strategy is to achieve long-term growth in production and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding production and reserves through the development of our Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex, Hackberry, Bakken, Three Forks, and Monterey Shale acreage.

Several of the key elements of our business strategy are as follows:

- Ø transition existing inventory of reserves into oil and natural gas production;
- Ø add to project inventory through ongoing prospect generation, exploration and strategic acquisitions; and
- Ø retain a greater percentage working interest in, and operatorship of, our projects going forward.

Our core competencies include generating:

- Ø unconventional oil resource plays;
- Ø onshore liquids-rich projects through the use of 3-D seismic surveys; and
- Ø identification of high impact deep onshore prospects located beneath known producing trends through the use of 3-D seismic surveys.

Our Key Strengths and Competitive Advantages

We believe the following key strengths and competitive advantages will allow us to successfully execute our business strategy:

- Ø *Extensive technical knowledge and history of operations in the Gulf Coast region* Since 1983 Yuma Co. or its predecessor has operated in the Gulf Coast region, which is an area that extends through Texas, Louisiana and Mississippi. Our extensive understanding of the geology and experience in interpreting well control, core and 3-D seismic data in this area provides us with a competitive advantage in exploring and developing projects in the Gulf Coast region. We have cultivated amicable and mutually beneficial relationships with acreage owners in this region and adjacent oil and natural gas operators, which generally provides for effective leasing and development activities.

- Ø *In-house technical expertise in 3-D seismic programs*. We design and generate in-house 3-D seismic survey programs on many of our projects. By controlling the 3-D seismic program from field acquisition through seismic processing and interpretation, we gain a competitive advantage through proprietary knowledge of the project.

- Ø *Liquids-rich, quality assets with attractive economics*. Our reserves and drilling locations are primarily oil plays with associated liquids-rich natural gas.

- Ø *Diversified portfolio of producing and non-producing assets*. Our current portfolio of producing and non-producing assets covers a large area within the U.S. Gulf Coast, the Bakken/Three Forks shale in North Dakota, and the Monterey Shale, along with shallow oil fields in central and southern California.

- Ø *Significant inventory of oil and natural gas assets*. We have a significant inventory of both proved reserves and significant growth assets that we believe can be developed over the near to medium term. In addition, we have the ability to organically generate new oil and natural gas prospects and projects through techniques utilized by our experienced management team, which include analyzing subsurface data, negotiating mineral rights with landowners in prospective areas, and shooting and reprocessing 3-D seismic surveys.

- Ø *Company operated assets*. In order to maintain better control over our assets, we have established a leasehold position comprised primarily of assets where we are the operator. By controlling operations, we are able to dictate the pace of development and better manage the cost, type, and timing of exploration and development activities.

- Ø *Experienced management team*. We have a highly qualified management team with many years of industry experience, including extensive experience in the Gulf Coast region. Our team has substantial expertise in the design, acquisition, processing and interpretation of 3-D seismic surveys, and our experienced operations staff allows for efficient turnaround from project identification, to drilling, to production.

- Ø *Experienced board of directors*. Our directors have substantial experience managing successful public companies and realizing value for investors through the development, acquisition and monetization of both conventional and unconventional oil and natural gas assets in the Gulf Coast region.

Description of Major Properties

We are the operator of properties containing approximately 82% of our proved oil and natural gas reserves as of December 31, 2014. As operator, we are able to directly influence exploration, development and production operations. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price fluctuations, and have provided a solid foundation for our technical staff to pursue the development of our undeveloped acreage, further develop our existing properties and also generate new projects that we believe have the potential to increase shareholder value.

As is common in the industry we participate in non-operated properties on a selective basis; our non-operating participation decisions are dependent on the technical and economic nature of the projects and the operating expertise and financial standing of the operators. The following is a description of our significant oil and natural gas properties.

Greater Masters Creek Field, Allen, Vernon, Rapides and Beauregard Parishes, Louisiana. Our Greater Masters Creek Field properties are located in the Austin Chalk Trend in west central Louisiana. At December 31, 2014, we held approximately 69,470 net acres in the field. The acreage is located within an existing field which has previously been partially developed. Based on our technical analysis and independent third-party engineering, we believe there are approximately 67 operated proved undeveloped locations and 14 non-operated proved undeveloped locations that are either held by production or leases.

In the fourth quarter of 2014, we completed our second operated Austin Chalk well, the Crosby 14-1, which was drilled vertically to approximately 15,000 feet to the top of the Austin Chalk formation and then 3,100 feet horizontally in the Austin Chalk formation. Upon completion of the Crosby 14-1, we shut the well in to install surface facilities and to drill a salt water disposal well. In December 2014, we produced the well for three days to test and complete the installation of the facilities. In January of 2015 we began to produce and clean-up the production from the Crosby 14-1 well. Although early production results were encouraging, with higher oil cuts than expected, drilling mud and cuttings accumulated in the well which prevented it from flowing. We are planning operations designed to reduce or eliminate these restrictions. Work-over operations are being prepared to bring the well back on production. We hold a 61% working interest in this well.

La Posada – Bayou Hebert Field, Vermilion Parish, Louisiana. We have a 12.5% working interest in La Posada – Bayou Hebert Field. The primary objectives were the Lower Planulina Cris R sands, at a depth from approximately 17,700 to 18,250 feet. We initially generated the exploration prospect by utilizing data from a 3-D seismic survey, which resulted in a significant discovery.

The prospect was successfully tested in 2011 on the southern portion of the structure by PetroQuest Energy, Inc., the operator. A brief summary of the drilling activity to date is as follows:

1. The Thibodeaux No. 1 well was drilled to a total depth of 19,079 feet and logged a net 217 feet of hydrocarbon bearing sand. The well was put on production in March 2012.

2. The Broussard No. 2 well was drilled to a depth of 19,150 feet on the north side of the structure in 2012. This well logged a net 328 feet of hydrocarbon bearing sand in the Lower Planulina Cris R-1 and Cris R-2A, B and C sandstones. The well was put on production in September 2012.

3. The Broussard No. 1 well (partially drilled and temporarily abandoned in 2007) was re-entered and sidetracked to the upper Cris R-2 sand as an acceleration well. The Broussard No. 1 sidetrack was drilled to a depth of 18,035 feet and encountered the upper productive sand in 2013. The well was put on production in May 2013.

In November 2014, after encountering excess water production relating to the wells, the operator reconfigured the production facilities and gross production averaged approximately 52.6 MMcf/d of natural gas and 970 Bbl/d of oil (4.7 MMcf/d and 87 Bbl/d net) during the fourth quarter of 2014. During the last week in January 2015, the operator completed the installation of higher capacity water handling equipment to handle increased water production from the Broussard No. 2 and the Thibodeaux No. 1. With the installation of this equipment, the operator plans to optimize gas production within the water handling limits of the upgraded facilities. As of March 15, 2015, the field was producing approximately 59 MMcf/d of natural gas and 1,100 Bbl/d of oil gross (5.3 MMcf/d and 98 Bbl/d net). Future potential production increases and the timing of potentially recompleting the Thibodeaux No. 1 from its current “C” zone to the overlying “B” zone will depend on the performance and optimization of the well.

Livingston Prospects, Livingston Parish, Louisiana. Our primary exploration targets which produce in the area include intermediate depth Wilcox sands and the deeper lower Tuscaloosa sands. We hold an average 33% working interest across the Livingston prospects and we are the operator.

To date we have drilled five exploration wells with four discoveries on our Livingston project. Three of the wells targeted the lower Tuscaloosa sands (oil), two of which were discoveries, one well targeted the Wilcox formation (oil), and one well was drilled to a shallow Miocene target (natural gas). The shallow Miocene well has produced out and has been shut in.

We have since drilled two development wells offsetting our Lower Tuscaloosa discoveries in addition to two development wells offsetting our Wilcox discovery. One of our Wilcox development wells, the Blackwell 39-1 was drilled and completed on January 14, 2015 and has averaged 73 Bbl/d of oil gross when producing during the two months ended March 16, 2015. We anticipate placing the Blackwell 39-1 on pump during the second quarter of 2015.

Currently, four wells are producing from the lower Tuscaloosa sands and three wells are producing from the Wilcox. The average daily production from the seven wells during the three months ended December 31, 2014 was approximately 391 Bbl/d of oil gross (90 Bbl/d net).

Lake Fortuna Field (Raccoon Island), St. Bernard Parish, Louisiana. We discovered our Lake Fortuna field in 1996 when our 3-D Raccoon Island prospect was drilled. The target was a Middle Miocene sand on a known productive structure. In 2005, we acquired the majority of the working interest in Raccoon Island from Amerada Hess, and now own a working interest of 91%. During the three months ended December 31, 2014, we temporarily shut in a portion of the field to repair a salt water disposal well which curtailed production and consequently resulted in lower revenues from the field. Normal production levels in the field are approximately 250 Bbl/d of oil gross (162 Bbl/d net).

Gardner Island and Branville Bay, St. Bernard Parish, Louisiana. During the fourth quarter of 2014, we performed repair work on the salt water disposal well servicing the two fields which was completed in January 2015. This resulted in reduced production and revenues from the field in the fourth quarter due to the downtime for the repair. Since the repair, the fields were produced for approximately six weeks and then shut in for facility upgrades. We anticipate completing the upgrades in March 2015 and restoring production to approximately 250 Bbl/d gross (63 Bb/d net). Additionally, during the fourth quarter of 2014 we acquired additional interest in our Gardner Island field bringing our working interest from 7% to 34%

Amazon 3-D Project, Calcasieu and Jefferson Parishes, Louisiana. In 2011, we shot a 70 square mile 3-D seismic survey targeting the Frio (Hackberry and Marg Tex/Cib Haz/Camerina objectives). The Hackberry is a "bright spot" play for natural gas with rich condensate yields found in stratigraphic traps at depths of approximately 13,000 feet. The Marg Tex/Cib Haz/Camerina objectives are found at depths typically around 9,000 feet in structural traps independent of the underlying Hackberry.

We have recently finished drilling our Anaconda prospect, the Talbot 23-1, where we hold approximately a 45% working interest after casing point. This single well prospect is unique in that it encountered both Hackberry and Marg Tex objectives.

In the Marg Tex interval, the well logged approximately 45 feet of hydrocarbon bearing pay in four Marg Tex sands. In the Hackberry interval, we logged approximately 45 feet of hydrocarbon bearing pay in two Hackberry sands. We plan to begin completion and testing operations in the near future.

Cat Canyon Field, Santa Barbara County, California. Our Cat Canyon field is a legacy asset that was developed and owned by Pyramid Oil Company prior to our merger completed on September 10, 2014. The field produces from the Monterey formation at a depth of 4,500 feet and is nearly 2,000 feet thick. We have a 100% working interest in 120 acres held by production in this field. The field is surrounded by Monterey wells drilled from the late 1940's through 1982 on 10 acre spacing. The wells are drilled vertically, completed naturally (without fracking) and are put on pump immediately. We plan to drill our first operated well on this property in 2015.

Bakken – Yellowstone and Southeast Homerun. At December 31, 2014, we held an average 5% non-operated working interest in 18,513 gross acres (674 net acres) in McKenzie County, North Dakota. We have interests in six producing oil wells and two active salt water disposal wells. All producing wells are located in two fields, Yellowstone and Southeast Homerun. The majority of our interests are currently operated by Zavanna, LLC. We currently estimate that approximately 140 gross drilling locations remain across our Bakken asset. In addition, we believe significant future infill and Three Forks development upside potential exists on our acreage.

Oil and Natural Gas Reserves

All of our oil and natural gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note X – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The reserve estimates have been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm. We have no long-term supply or similar agreements with foreign governments or authorities. We did not provide any reserve information to any federal agencies in 2014 other than to the SEC.

Estimated Proved Reserves

The table below summarizes our estimated proved reserves at December 31, 2014 based on the report prepared by NSAI. In preparing these reports, NSAI evaluated 100% of our properties at December 31, 2014. For more information regarding our independent reserve engineers, please see Independent Reserve Engineers below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)	Present Value Discounted at 10% ($ in thousands) (2)
Proved developed (3)					
Greater Masters Creek Field (4)	515	100	1,043	789	$ 15,134
Other	1,520	212	6,744	2,856	79,497
Total proved developed	2,035	312	7,787	3,645	94,631
Proved undeveloped (3)					
Greater Masters Creek Field (4)	8,972	2,060	23,095	14,882	272,094
Other	525	107	4,378	1,361	14,321
Total proved undeveloped	9,497	2,167	27,473	16,243	286,415
Total proved (3)	11,532	2,479	35,260	19,888	$ 381,046

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Present Value Discounted at 10% ("PV10") is a Non-GAAP measure that differs from the GAAP measure "standardized measure of discounted future net cash flows" in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of the PV10 value is relevant and useful to investors because it presents the estimated discounted future net cash flows attributable to our estimated proved reserves independent of our income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, we believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties. PV10 does not necessarily represent the fair market value of oil and natural gas properties.

PV10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For a presentation of the standardized measure of discounted future net cash flows, see Note X – Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The table below titled "Non-GAAP Reconciliation" provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Non-GAAP Reconciliation *($ in thousands)*

The following table reconciles our direct interest in oil, natural gas and natural gas liquids reserves as of December 31, 2014:

Present value of estimated future net revenues (PV10)	$	381,046
Future income taxes discounted at 10%		(86,591)
Standardized measure of discounted future net cash flows	$	294,455

(3) Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months, which were $91.48 per Bbl (WTI) and $4.35 per MMBtu (HH), for the year ended December 31, 2014. Adjustments were made for location and grade.

(4) Our Greater Masters Creek Field is our only field that contained 15% or more of our estimated proved reserves as of December 31, 2014.

Proved Undeveloped Reserves

At December 31, 2014, our estimated proved undeveloped reserves ("PUDs") were approximately 16,243 MBoe. The following table details the changes in proved undeveloped reserves for the year ended December 31, 2014 (in MBoe):

Beginning proved undeveloped reserves at January 1, 2014	16,958
Undeveloped reserves transferred to developed	(189)
Purchases of minerals-in-place	-
Extensions and discoveries	-
Production	-
Revisions	(526)
Proved undeveloped reserves at December 31, 2014	16,243

From January 1, 2014 to December 31, 2014, our PUDs decreased 4% from 16,958 MBoe to 16,243 MBoe, or a decrease of 715 MBoe. Reserves of 189 MBoe were moved from the PUD reserve category to the proved developed producing category through the drilling of the Crosby 14-1 and Bertha 8-3 wells. We incurred approximately $16.7 million in capital expenditures during the year ended December 31, 2014 in converting these wells to the proved developed reserve category. The remaining change in PUDs of 526 MBoe was a result of decreased prices and performance revisions over the time period. Based on our 2014 year-end independent engineering reserve report, we plan to drill all of our PUD drilling locations within five years.

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of the estimates, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Technology Used to Establish Reserves

Under the SEC rules proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using both volumetric estimates and performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Independent Reserve Engineers

We engaged NSAI to prepare our annual reserve estimates and have relied on NSAI's expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are G. Lance Binder and Philip R. Hodgson. Mr. Binder has been practicing consulting petroleum engineering at NSAI since 1983. Mr. Binder is a Registered Professional Engineer in the State of Texas (No. 61794) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science degree in Chemical Engineering. Mr. Hodgson has been practicing consulting petroleum geology at NSAI since 1998. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1314) and has over 30 years of practical experience in petroleum geosciences. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our principal engineer was primarily responsible for overseeing our independent petroleum engineering firm during the preparation of our reserve report. His professional qualifications met or exceeded the qualifications of reserve estimators and auditors set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications included: Bachelors of Science degree in Petroleum Engineering from Texas A&M University, 1999; Masters in Finance from the University of Houston in 2008; Executive Masters of Business Administration degree from Rice University in 2011; member of the Society of Petroleum Engineers since 1998; and more than 14 years of experience in the oil and gas industry.

Internal Control over Preparation of Reserve Estimates

We maintain adequate and effective internal controls over our reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are technical information, financial data, ownership interest, and production data. The relevant field and reservoir technical information, which is updated annually, is assessed for validity when our independent petroleum engineering firm has technical meetings with our engineers, geologist, operations and land personnel. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field-level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to our internal controls over financial reporting, and they are incorporated in our reserve database as well and verified internally by us to ensure their accuracy and completeness. Once the reserve database has been updated with current information, and the relevant technical support material has been assembled, our independent engineering firm meets with our technical personnel to review field performance and future development plans in order to further verify the validity of estimates. Following these reviews the reserve database is furnished to NSAI so that it can prepare its independent reserve estimates and final report. The reserve estimates prepared by NSAI are reviewed and compared to our internal estimates by our principal engineer and staff in our reservoir engineering department. Material reserve estimation differences are reviewed between NSAI's reserve estimates and our internally prepared reserves on a case-by-case basis. An iterative process between NSAI and us, and additional data is provided to address the differences. If the supporting documentation will not justify additional changes, the NSAI reserves are accepted. In the event that additional data supports a reserve estimation adjustment, NSAI will analyze the additional data, and may make changes it deems necessary. Additional data is usually comprised of updated production information on new wells. Once the review is completed and all material differences are reconciled, the reserve report is finalized and our reserve database is updated with the final estimates provided by NSAI. Access to our reserve database is restricted to specific members of our reservoir engineering department and management.

Production, Average Price and Average Production Cost

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

	Years Ended December 31,		
	2014	2013	2012
Production volumes:			
Crude oil and condensate (Bbls)	231,816	184,349	154,437
Natural gas (Mcf)	2,714,586	1,580,468	515,112
Natural gas liquids (Bbls)	97,783	51,875	9,571
Total (Boe) (1)	782,030	499,635	249,860
Average prices realized:			
Excluding commodity derivatives (both realized and unrealized):			
Crude oil and condensate (per Bbl)	$ 93.98	$ 104.26	$ 107.57
Natural gas (per Mcf)	$ 4.62	$ 3.83	$ 3.07
Natural gas liquids (per Bbl)	$ 38.44	$ 40.17	$ 42.67
Including commodity derivatives (realized only):			
Crude oil and condensate (per Bbl)	$ 91.74	$ 102.46	$ 106.45
Natural gas (per Mcf)	$ 4.32	$ 4.08	$ 4.07
Natural gas liquids (per Bbl)	$ 38.44	$ 40.17	$ 42.67
Production cost per Boe (2)	$ 11.60	$ 12.40	$ 11.99

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

(2) Excludes ad valorem taxes (which are included in lease operating expenses on our Consolidated Statements of Operations in the Consolidated Financial Statements in Part II, Item 8 in this report) and severance taxes, totaling $3,741,513, $3,121,185, and $2,104,025 in fiscal years 2014, 2013, and 2012, respectively.

Effective January 1, 2013, we acquired our interest in the Greater Masters Creek Field, which contained 79% and 78% of our total proved reserves as of December 31, 2014 and 2013, respectively. No other single field accounted for 15% or more of our proved reserves as of December 31, 2014 and 2013. The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2014 and 2013, the average sales price per unit sold and the average production cost per unit for the Greater Master Creek Field are presented below.

	Years Ended December 31,	
Greater Masters Creek Field	2014	2013
Production volumes:		
Crude oil and condensate (Bbls)	45,656	24,972
Natural gas (Mcf)	170,916	85,866
Natural gas liquids (Bbls)	16,558	8,702
Total (Boe) (1)	90,700	47,985
Average prices realized: (2)		
Crude oil and condensate (per Bbl)	$ 95.29	$ 100.87
Natural gas (per Mcf)	$ 4.68	$ 4.07
Natural gas liquids (per Bbl)	$ 33.67	$ 34.98
Production cost per Boe (3)	$ 43.10	$ 55.89

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).
(2) Excludes commodity derivatives (realized and unrealized) as they are not recorded by specific field.
(3) Excludes ad valorem taxes (which are included in lease operating expenses on our Consolidated Statements of Operations in the Consolidated Financial Statements in Part II, Item 8 in this report) and severance taxes, totaling $1,111,162 and $875,488 in fiscal years 2014 and 2013, respectively.

Our La Posada (Bayou Herbert) field contained 17% of our total proved reserves as of December 31, 2012. No other single field accounted for 15% or more of our proved reserves as of December 31, 2012. The net quantities of oil, natural gas and natural gas liquids produced and sold by us for the year ended December 31, 2012, the average sales price per unit sold and the average production cost per unit for our La Posada (Bayou Herbert) field are presented below.

	Year Ended December 31, 2012
La Posada (Bayou Herbert) Field	
Production volumes:	
Crude oil and condensate (Bbls)	6,780
Natural gas (Mcf)	345,309
Natural gas liquids (Bbls)	8,442
Total (Boe) (1)	72,774
Average prices realized: (2)	
Crude oil and condensate (per Bbl)	$ 107.68
Natural gas (per Mcf)	$ 3.17
Natural gas liquids (per Bbl)	$ 43.05
Production cost per Boe (3)	$ 2.54

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).
(2) Excludes commodity derivatives (realized and unrealized) as they are not recorded by specific field.
(3) Excludes severance taxes but includes ad valorem taxes in lease operating expenses since this well is non-operated by us and the operator does not break-out the ad valorem taxes from lease operating expenses.

Gross and Net Productive Wells

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

Oil (1)		Natural Gas (1)		Total (1)	
Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
83	42	37	2	120	44

(1) A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractions of working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production. Horizontal re-entries of existing wells do not increase a well total above one gross well. We have working interests in 10 gross wells with completions into more than one productive zone; in the table above, these wells with multiple completions are only counted as one gross well.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2014, we had total gross and net developed and undeveloped leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated or permitted by state regulatory authorities. Gross acres are those acres in which a working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

	Developed		Undeveloped		Total	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Louisiana	100,839	52,822	28,882	20,815	129,721	73,637
North Dakota	18,553	674	-	-	18,553	674
Texas	2,761	306	-	-	2,761	306
Oklahoma	2,160	96	-	-	2,160	96
California	1,422	1,400	-	-	1,422	1,400
New York	12,246	4,082	-	-	12,246	4,082
Wyoming	7,360	3	-	-	7,360	3
Total	145,341	59,383	28,882	20,815	174,223	80,198

As of December 31, 2014, we had leases representing 2,965 net acres (1,329 of which were in the Greater Masters Creek Field) expiring in 2015; 1,921 net acres (1,647 of which were in the Greater Masters Creek Field) expiring in 2016; and 6,336 net acres (6,256 of which were in the greater Masters Creek Field) expiring in 2017 and beyond. We anticipate that our current and future drilling plans, along with selected lease extensions, will address the majority of the leases expiring in the Greater Masters Creek Field and our other fields in 2015 and beyond.

Exploratory Wells and Development Wells

Set forth below for the years ended December 31, 2014, 2013 and 2012 is information concerning our drilling activity during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells
Year	**Productive**	**Dry**	**Productive**	**Dry**	**Drilled**
2014	.61	-	.54	-	1.15
2013	.32	-	.57	.31	1.21
2012	.33	.28	.64	-	1.25

Present Activities

At March 25, 2015, we had 1.0 gross (.45 net) wells in the process of drilling or completing.

Supply Contracts or Agreements

Crude oil and condensate are sold through month-to-month evergreen contracts. The price is tied to an index or a weighted monthly average of posted prices with certain adjustments for gravity, BS&W (Basic Sediment and Water) and transportation. Generally, the index or posting is based on WTI (West Texas Intermediate) and adjusted to LLS (Light Louisiana Sweet) or HLS (Heavy Louisiana Sweet). For the years ended December 31, 2014, 2013 and 2012, the LLS postings averaged $3.02, $9.58, and $17.16 over WTI, respectively. Pricing for our California properties is based on an average of specified posted prices, adjusted for gravity, transportation, and for one field, a market differential.

Our natural gas is sold under multi-year contracts with pricing tied to either first of the month index or a monthly weighted average of purchaser prices received. Natural gas liquids are also sold under multi-year contacts usually tied to the related natural gas contract. Pricing is based on published prices for each product or a monthly weighted average of purchaser prices received.

We also engage in hedging activities as discussed below in “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Hedging Activities.”

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Major Customers

The purchasers of our oil, natural gas and natural gas liquids production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2014, two individual purchasers of our production, PetroQuest Energy, LLC and GulfMark Energy, Inc. each accounted for more than 10% of our total sales, and two purchasers, Gavilon, LLC and Genesis Crude Oil, L.P. each accounted for more than 6% of our total sales, collectively representing 74% of our total sales for the year.

In 2013, two individual purchasers of our production, PetroQuest Energy, LLC and GulfMark Energy, Inc., each accounted for more than 10% of our total sales, and two purchasers, Hilcorp Energy Company and

Genesis Crude Oil, L.P., each accounted for more than 7% of our sales, collectively representing 78% of our total sales for the year.

In 2012, four individual purchasers of our production, PetroQuest Energy, LLC, GulfMark Energy, Inc., Hilcorp Energy Company, and Genesis Crude Oil, L.P., each accounted for more than 10% of our total sales, collectively representing 79% of our total sales for the year.

We believe there are adequate alternate purchasers of our production such that the loss of one or more of the above purchasers would not have a material adverse effect on our results of operations or cash flows.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental leakage or spills of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion of risks see Item 1A. Risk Factors of this report.

Title to Properties

We believe that the title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically regulate the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

New programs and changes in existing programs, however, may address various aspects of our business including natural occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and natural gas wastes and reclassify them as hazardous wastes. If such proposals were to be enacted, they could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

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

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA"), the Underground Injection Control ("UIC") regulations promulgated under the SDWA and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and natural gas production.

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

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

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

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

Climate Change

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

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

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

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

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Although the Company has a few future projects that could potentially involve federal lands, federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of future oil and natural gas projects.

Threatened and endangered species, migratory birds and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communication and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act and may require that information be provided to state and local government authorities and the public.

Occupational Safety and Health Act

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

Employees and Principal Office

As of December 31, 2014, we had 41 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Our principal executive office is located at 1177 West Loop South, Suite 1825, Houston, Texas 77027, where we occupy approximately 15,180 square feet of office space. Our Bakersfield office, consisting of approximately 4,200 square feet, is located at 2008 Twenty-First Street, Bakersfield, California 93301.

We owned the following real property as of December 31, 2014, all located in Kern county in the State of California: Mullaney yard (20 acres), Miller property (112 acres), Ranton property (80 acres), Murphy property (50 acres) and in the City of Bakersfield (3 lots).

Recent Developments

Merger – Change in Management, Control and Business Strategy

On September 10, 2014, a wholly owned subsidiary of the Company merged with and into Yuma Co., in exchange for 66,336,701 shares of common stock and we changed our name to "Yuma Energy, Inc." (the "merger"). As a result of the merger, the former Yuma Co. stockholders received approximately 93% of the then outstanding common stock of the Company and thus acquired voting control. Although the Company was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of the Company by Yuma Co.

Subsequent to the merger, Sam L. Banks assumed the role of Chairman, President and Chief Executive Officer, Paul D. McKinney became Executive Vice President and Chief Operating Officer, and Kirk F. Sprunger became Chief Financial Officer, Treasurer and Corporate Secretary. Our board of directors was reconstituted to include the directors of Yuma Co., Sam L. Banks, James W. Christmas, Frank A. Lodzinski, Ben T. Morris, Richard K. Stoneburner, and Richard W. Volk. Also, as part of the merger, our headquarters were relocated to Houston, Texas.

Issuance of 9.25% Series A Cumulative Redeemable Preferred Stock

On October 23, first closing, and then on October 24, 2014, final closing, we closed a public offering of 507,739 shares of our 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share, with a liquidation preference of $25.00 per share (the "Series A Preferred Stock"), at a public offering price of $22.00 per share, with aggregate net proceeds of $10,555,893, net of the underwriters' discount and underwriters' expenses.

At-the-Market Issuance Sales Agreement

On December 19, 2014, we entered into an At-the-Market Issuance Sales Agreement (the "sales agreement") with an investment banking firm (the "Agent"). Under this sales agreement, we could issue and sell from time to time, up to $18,829,742 in the aggregate of shares of our Series A Preferred Stock and shares of our common stock. The offer and sale of these shares are registered under a universal shelf registration statement filed with the SEC on November 21, 2013. The sales agreement provides that our Series A Preferred Stock and our common stock will be sold at market prices prevailing at the time of the sale of such shares, at no discount to market. We were not obligated to make any sales under the sales agreement. We have agreed to pay the Agent a commission rate of up to 6.0% of the gross proceeds from the sale of shares of Series A Preferred Stock and shares of our common stock sold through the Agent under the sales agreement, reimburse the Agent for certain expenses incurred in connection with entering into the sales agreement, and provide the Agent with customary indemnification rights. The full terms and text of the sales agreement were filed with our Current Report on Form 8-K on December 29, 2014. Through March 25, 2015, we have sold 37,769 shares of Series A Preferred Stock and 221,159 shares of our common stock under the sales agreement.

Amendment to Senior Credit Agreement

On January 23, 2015, we entered into the Sixth Amendment to our Credit Agreement (the "credit agreement") with Société Générale (the "Bank") as Administrative Agent, which provides for a line of credit until May 20, 2017. Pursuant to the credit agreement, we secured a credit facility (the "credit facility"), which is available to provide financing of up to $40.0 million. The credit agreement is secured by a first lien on substantially all of the Company's assets. The credit facility has a $40.0 million conforming borrowing base, and is subject to redetermination on March 1 and October 1 of each year. As of March 25, 2015, the borrowing base was $40.0 million and long-term debt outstanding was approximately $26.7 million. At this time, the borrowing base is in the process of redetermination. The Company expects the borrowing base to be reset at a somewhat lower value. Amounts borrowed under the credit agreement bear interest at either (a) the LIBOR rate plus 2.25% to 3.75% or (b) the prime rate plus 1.25% to 2.75%, depending on the amount borrowed under the credit facility. The credit facility contains a number of covenants that, among other things, restrict, subject to certain exceptions, our ability to incur additional indebtedness, create liens on assets, sell certain assets and engage in certain transactions with affiliates. Additionally, the credit agreement contains a covenant restricting the payment of dividends on preferred stock if there is less than ten percent availability on the borrowing base. The credit facility also requires the maintenance of certain financial ratios. See Part II, Item 8. Notes to the Consolidated Financial Statements, Note L – Debt and Change in Banking Line and Agent Bank.

Item 1A. Risk Factors.

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Cautionary Statement Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

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

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

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

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

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

Our operations and future development activities are concentrated in the Greater Masters Creek Field in west central Louisiana. In the event the field does not meet our expectations with respect to drilling and future production or we are unable to develop the field due to capital constraints, our future business, financial condition and results of operations will be materially adversely affected.

As set forth elsewhere in this report, our Greater Masters Creek Field in west central Louisiana is our largest oil and gas development project. At December 31, 2014 we held approximately 69,470 net acres in the field. Although the acreage has been partially developed by prior operators, our internal geological and engineering evaluation, as substantiated by two independent third-party engineering firms, supports the presence of significant remaining proved undeveloped reserves and additional potential. Our independent petroleum engineering reserve report as of December 31, 2014 includes 67 operated proved undeveloped well locations and 14 non-operated proved undeveloped well locations that are held by production or leases in the field. During 2014, we completed our second operated Austin Chalk well, the Crosby 14-1. While this well has encountered bottom-hole pressure consistent with our third-party engineering estimates and demonstrated encouraging initial production results, we encountered significant mechanical difficulties while drilling and completing the well. Consequently, costs to drill and complete the well significantly exceeded our pre-drill estimates. In addition, this well's production has been scaled back due to restrictions in the well bore, including down-hole drilling motor components, which could not be recovered. Our current estimates of the future capital required to develop the proved undeveloped well locations in the field have been made taking into account our experience with the Crosby 14-1.

As of December 31, 2014, the field contained approximately 91.6% of our total proved undeveloped reserves and 95.0% of the PV-10 of such reserves. Additionally, the field's proved undeveloped reserves represent approximately 74.8% of our total proved reserves. Because such a significant portion of our operations are concentrated in the field, the success of our operations and our profitability may be disproportionately exposed to the effect of various events with respect to the field, including but not limited to unanticipated costs and delays in drilling, fluctuations in prices of natural gas and oil produced from wells, natural disasters, restrictive governmental regulations, transportation capacity constraints, inclement weather, curtailment of production due to unforeseen events, and any resulting delays or interruptions of production from existing or planned new wells in the field. We intend to drill and complete the proposed wells in this field in accordance with our development plan, which is based on substantial technical engineering analyses. However, in the event our assumptions and analyses regarding the field are incorrect to any significant degree, the future production from the wells to be drilled may be adversely affected, which in turn could materially adversely affect our business, financial condition and results of operations. In addition, our development plan as of January 1, 2015 assumes that the net capital for development of the field will be approximately $377.5 million. Our ability to have sufficient capital in accordance with our plan to complete the development of these undeveloped reserves will be subject to our future cash flows, future prices for oil and gas, as well as our capital raising abilities. Any significant sustained decrease in the price of oil and gas or our ability to obtain financing, either debt or equity, could have a significant negative impact on our ability to develop the field as planned and hence, realize the positive cash flow and net income as estimated elsewhere in this report.

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

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Further deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of operational issues, weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flow and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2014, approximately 82% of our estimated reserves (as consolidated with our two subsidiaries) were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations; however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this report which could have a material effect on the value of our reserves.

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

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment and increased drilling and production costs;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or salt water, into the environment;
- hazards resulting from the presence of hydrogen sulfide or other contaminants in natural gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially affected and may differ materially from those anticipated by us.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- downhole and well completion difficulties;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

We are subject to complex federal, state, local and other laws and regulations that from time to time are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, air emissions, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we have operated and non-operated working interests and the operator of such properties could be subject to additional levels of regulation, operational delays or increased operating costs and could have regulatory burdens imposed upon it that could make it more difficult to perform hydraulic fracturing and increase the costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the Safe Drinking Water Act ("SDWA") to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Further, the EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing, including for example, a BLM rulemaking for hydraulic fracturing practices on federal and Indian lands that has resulted in a May 2013 proposal that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business with regard to our operated and non-operated properties.

Certain states likewise have adopted, and other states are considering the adoption of regulations that impose new or more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

As a working interest owner, we use a significant amount of water with respect to hydraulic fracturing operations. The inability to locate sufficient amounts of water, or dispose of or recycle water used in exploration and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to participate in certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. Compliance with environmental regulations and regulatory permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase the operating costs of our properties and cause delays, interruptions or termination of operations, all of which could have an adverse effect on our results of operations and financial condition. Further, if the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

Hydraulic fracturing involves the injection of water, sand and various chemicals under pressure into geologic formations to fracture the surrounding rock and stimulate production. This process may give rise to operational issues such as an underground migration of water and chemicals to unintended areas, wellbore integrity, possible surface spillage and contamination caused by mishandling of fracturing fluids, including chemical additives. Properly administering the hydraulic fracturing process entails operational costs and a failure to properly administer the process could cause significant remedial and financial costs.

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

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

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

At the federal level, the Obama Administration is attempting to address climate change through a variety of administrative actions. The EPA has issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an “Endangerment Finding” under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, the President released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA has released five draft white papers on methane and volatile organic compound emissions and mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities and natural gas production and transmission facilities. Building on its white papers and the public input on those documents, the EPA has announced that it intends to issue a proposed rule in the summer of 2015 to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. Also as part of the President's strategy, the BLM is expected to propose standards for reducing venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

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

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

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

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

The CFTC also has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin and position limits; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the Dodd-Frank Act and the CFTC regulations may require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain of our derivative activities. Also, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. It is possible that the CFTC, in conjunction with the U.S. federal banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which we would be required to post collateral.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts, and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The oil and natural gas industry is cyclical and, from time to time, there have been shortages of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third-party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of third-party operators to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could materially affect our results of operations.

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

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

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

Risks Related to the Ownership of our Common Stock

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

Sam L. Banks, our Chairman, President and Chief Executive Officer, beneficially owns a majority of our common stock. As a result, we are a “controlled company” within the meaning of the NYSE MKT corporate governance standards. Under the NYSE MKT rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE MKT corporate governance requirements, including the requirements that:

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

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

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

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

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

We are able to issue shares of preferred stock with greater rights than our common stock.

Our Restated Articles of Incorporation authorize our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our shareholders. The preferred shares that we have issued rank ahead of our common stock in terms of dividends and liquidation rights. We may issue additional preferred shares that rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred shares in the future, it may adversely affect the market price of our common stock. We have issued in the past, and may in the future continue to issue, in the open market at prevailing prices or in capital markets offerings series of perpetual preferred stock with dividend and liquidation preferences that rank ahead of our common stock.

Because we have no plans to pay dividends on our common stock, shareholders must look solely to appreciation of our common stock to realize a gain on their investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, our credit agreement contains covenants that prohibit us from paying cash dividends on our common stock as long as such debt remains outstanding. The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. Accordingly, shareholders must look solely to appreciation of our common stock to realize a gain on their investment, which may not occur.

Risks Related to the Ownership of our Series A Preferred Stock

The Series A Preferred Stock ranks junior to all of our indebtedness and other liabilities and is effectively junior to all indebtedness and other liabilities of our subsidiaries.

In the event of our bankruptcy, liquidation, dissolution or winding-up of our affairs, our assets will be available to pay obligations on the Series A Preferred Stock only after all of our indebtedness and other liabilities have been paid. The rights of holders of the Series A Preferred Stock to participate in the distribution of our assets will rank junior to the prior claims of our current and future creditors and any future series or class of preferred stock we may issue that ranks senior to the Series A Preferred Stock. As of March 25, 2015, 545,508 shares of Series A Preferred Stock, having a liquidation value of $25 per share, are outstanding. If we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets to pay amounts due on any or all of the Series A Preferred Stock then outstanding. We and our subsidiaries have incurred and may in the future incur substantial amounts of debt and other obligations that will rank senior to the Series A Preferred Stock. At March 25, 2015, we had $26.7 million of bank debt, on a consolidated basis, ranking senior to the Series A Preferred Stock. Our credit facility prohibits payments of dividends on the Series A Preferred Stock if we fail to comply with certain financial covenants or, at certain times, if a default or event of default has occurred. Certain of our other existing or future debt instruments may restrict the authorization, payment or setting apart of dividends on the Series A Preferred Stock.

Future offerings of debt or senior equity securities may adversely affect the market price of the Series A Preferred Stock. If we decide to issue debt or senior equity securities in the future, it is possible that these securities will be governed by an indenture or other instruments containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of the Series A Preferred Stock and may result in dilution to owners of the Series A Preferred Stock. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. The holders of the Series A Preferred Stock will bear the risk of our future offerings, reducing the market price of the Series A Preferred Stock and diluting the value of their holdings in us.

We may not be able to pay dividends in cash on the Series A Preferred Stock.

Under California law, cash dividends may be paid only if either (1) our retained earnings exceed the amount of the distribution plus the amount, if any, of dividends in arrears on shares with preferential dividend rights, or (2) our total assets are not less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the distribution to satisfy the preferential rights upon dissolution of shareholders whose preferential rights on dissolution are superior to those receiving the distribution. Further, notwithstanding these factors, we may not have sufficient cash to pay dividends on the Series A Preferred Stock. Our ability to pay dividends may be impaired if any of the risks described in this report, were to occur. In addition, payment of our dividends depends upon our financial condition and other factors as our board of directors may deem relevant from time to time. We cannot make assurances that our business will generate sufficient cash flow from operations or that future borrowings will be available to us in an amount sufficient to enable us to make distributions on our Series A Preferred Stock, or to pay our indebtedness or to fund our other liquidity needs.

The Series A Preferred Stock has not been rated.

We have not sought to obtain a rating for the Series A Preferred Stock. No assurance can be given, however, that one or more rating agencies might not independently determine to issue such a rating or that such a rating, if issued, would not adversely affect the market price of the Series A Preferred Stock. In addition, we may elect in the future to obtain a rating for the Series A Preferred Stock, which could adversely affect the market price of the Series A Preferred Stock. Ratings only reflect the views of the rating agency or agencies issuing the ratings and such ratings could be revised downward, placed on a watch list or withdrawn entirely at the discretion of the issuing rating agency if, in its judgment, circumstances so warrant. Any such downward revision, placing on a watch list, or withdrawal of a rating could have an adverse effect on the market price of the Series A Preferred Stock.

Holders of Series A Preferred Stock may not be able to exercise conversion rights upon a Change of Control, and, if exercisable, these conversion rights may not adequately compensate you.

Upon the occurrence of a Change of Control, each holder of the Series A Preferred Stock will have the right (unless, prior to the Change of Control Conversion Date, we have provided notice of our election to redeem some or all of the shares of Series A Preferred Stock held by such holder, in which case such holder will have the right only with respect to shares of Series A Preferred Stock that are not called for redemption) to convert some or all of such holder's Series A Preferred Stock into shares of our common stock (or under specified circumstances involving certain alternative consideration).

Although we generally may not redeem the Series A Preferred Stock prior to October 23, 2017 (and we are subject to a general prohibition on redemptions under the terms of our credit facility prior to the date which is 30 days after all of our obligations and the lender commitments under those credit facilities have been satisfied), we have a special optional redemption right to redeem the Series A Preferred Stock in the event of a Change of Control, and holders of the Series A Preferred Stock will not have the right to convert any shares that we have elected to redeem prior to the Change of Control Conversion Date.

If we do not elect to redeem or are prohibited from redeeming the Series A Preferred Stock prior to the Change of Control Conversion Date, then, upon an exercise of the applicable conversion rights, the number of shares of our common stock or other applicable consideration that the holders of Series A Preferred Stock will be entitled to receive will be limited to a maximum of 14.12 multiplied by the number of shares of Series A Preferred Stock to be converted.

The market price of the Series A Preferred Stock could be substantially affected by various factors.

The market price of the Series A Preferred Stock will depend on many factors, which may change from time to time, including:

- prevailing interest rates, increases in which may have an adverse effect on the market price of the Series A Preferred Stock;
- trading prices of common and preferred equity securities issued by other energy companies;
- the annual yield from distributions on the Series A Preferred Stock as compared to yields on other financial instruments;
- general economic and financial market conditions;
- government action or regulation;
- the financial condition, performance and prospects of us and our competitors;
- changes in financial estimates or recommendations by securities analysts with respect to us, or competitors in our industry;
- our issuance of additional preferred equity or debt securities; and
- actual or anticipated variations in quarterly operating results of us and our competitors.

As a result of these and other factors, investors who purchase the Series A Preferred Stock may experience a decrease, which could be substantial and rapid, in the market price of the Series A Preferred Stock, including decreases unrelated to our operating performance or prospects.

We may issue additional shares of Series A Preferred Stock and additional series of preferred stock that rank on parity with the Series A Preferred Stock as to dividend rights, rights upon liquidation, or voting rights.

We are allowed to issue additional shares of Series A Preferred Stock and additional series of preferred stock that would rank equally to the Series A Preferred Stock as to dividend payments and rights upon our liquidation, dissolution or winding up of our affairs pursuant to our restated articles of incorporation, as amended, and the certificate of determination for the Series A Preferred Stock without any vote of the holders of the Series A Preferred Stock. The issuance of additional shares of Series A Preferred Stock and preferred stock that would rank on parity with the Series A Preferred Stock could have the effect of reducing the amounts available to the current holders of our Series A Preferred Stock upon our liquidation or dissolution or the winding up of our affairs. It also may reduce dividend payments to the current holders of the Series A Preferred Stock if we do not have sufficient funds to pay dividends on all Series A Preferred Stock outstanding and other classes of stock with equal priority with respect to dividends.

In addition, although holders of Series A Preferred Stock are entitled to limited voting rights with respect to such matters, the Series A Preferred Stock will vote separately as a class along with the holders of all other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series A Preferred Stock. As a result, the voting rights of holders of Series A Preferred Stock may be significantly diluted, and the holders of such other series of preferred stock that we may issue may be able to control or significantly influence the outcome of any vote.

Future issuances and sales of preferred stock ranking on parity with the Series A Preferred Stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series A Preferred Stock and our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Holders of Series A Preferred Stock have extremely limited voting rights.

Voting rights as a holder of Series A Preferred Stock is limited. Our shares of common stock are the only class of our securities that carry full voting rights. Voting rights for holders of Series A Preferred Stock exist primarily with respect to the ability to elect, voting together with the holders of any other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series A Preferred Stock, two additional directors to our board of directors, subject to certain limitations, in the event that a “Listing Event” (defined below) occurs or if we do not pay dividends on the Series A Preferred Stock for any monthly dividend period within a quarterly period for a total of six (6) consecutive or non-consecutive quarterly periods, and with respect to voting on amendments to our restated articles of incorporation, as amended, or certificate of determination relating to the Series A Preferred Stock that materially and adversely affect the rights of the holders of Series A Preferred Stock or authorize, increase or create additional classes or series of our shares that are senior to the Series A Preferred Stock. A “Listing Event” means, with respect to the Series A Preferred Stock, if that class of stock is not listed on certain specified national stock exchanges (including the New York Stock Exchange, NYSE MKT or NASDAQ) for 180 or more consecutive days. Other than the limited circumstances described in this Annual Report, holders of Series A Preferred Stock do not have any voting rights.

The Series A Preferred Stock is a relatively new issue of securities and has only a limited trading market, which may negatively affect its value and the ability to transfer and sell shares.

The Series A Preferred Stock is a relatively new issue of securities with only a limited trading market. The volume of trades of shares of the Series A Preferred Stock on the NYSE MKT is often low, and an active trading market on the NYSE MKT for the Series A Preferred Stock may not be maintained in the future and may not provide adequate liquidity. The liquidity of any market for the Series A Preferred Stock that may exist now or in the future will depend on a number of factors, including prevailing interest rates, the dividend rate on our common stock, our financial condition and operating results, the number of holders of the Series A Preferred Stock, the market for similar securities and the interest of securities dealers in making a market in the Series A Preferred Stock. As a result, the ability to transfer or sell the Series A Preferred Stock could be adversely affected.

If the Series A Preferred Stock or our common stock is delisted, the ability to transfer or sell shares of the Series A Preferred Stock may be limited, and the market value of the Series A Preferred Stock will likely be materially adversely affected.

Other than in connection with a Change of Control, the Series A Preferred Stock does not contain provisions that are intended to protect shareholders if our common stock is delisted from the NYSE MKT. Since the Series A Preferred Stock has no stated maturity date, shareholders may be forced to hold their shares of the Series A Preferred Stock and receive stated dividends on the Series A Preferred Stock when, and if authorized by our board of directors and paid by us with no assurance as to ever receiving the liquidation value thereof. In addition, if our common stock is delisted from the NYSE MKT, it is likely that the Series A Preferred Stock will be delisted from the NYSE MKT as well. Accordingly, if the Series A Preferred Stock or our common stock is delisted from the NYSE MKT, the ability to transfer or sell shares of the Series A Preferred Stock may be limited and the market value of the Series A Preferred Stock will likely be materially adversely affected.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is included in Item 1. Business and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

Item 3. Legal Proceedings.

A description of our legal proceedings is included in Part II, Item 8. Consolidated Financial Statements and Supplementary Data, Note P – Contingencies, and is incorporated herein by reference.

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not currently involved in any legal proceedings, nor are we a party to any pending or threatened claims, that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Our common stock has been listed for trading on the NYSE MKT under the symbol "YUMA" since September 11, 2014. Prior to that date, the common stock was traded on the NYSE MKT under the symbol "PDO". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock on the NYSE MKT.

	Common Stock Price	
	High	Low
Quarter Ended		
2013		
March 31	$ 4.50	$ 3.89
June 30	4.38	3.77
September 30	5.00	4.03
December 31	5.89	4.28
2014		
March 31	$ 7.15	$ 4.86
June 30	6.30	5.03
September 30	5.92	3.81
December 31	4.28	1.71

As of March 25, 2015, there were approximately 1,912 shareholders of record of our common stock. The actual number of holders of our common stock is greater than the number of record holders and includes shareholders who are beneficial owners, but whose shares are held in street name by brokers and nominees.

Dividends

We have not paid cash dividends on our common stock in the past two years and we do not anticipate that we will declare or pay dividends on our common stock in the foreseeable future. Payment of dividends, if any, is within the sole discretion of our board of directors and will depend, among other factors, upon our earnings, capital requirements and our operating and financial condition. In addition under California law, we may not pay a dividend if, after giving effect, we would be unable to pay our debts as they become due in the usual course of business or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the payment of the dividend to satisfy the preferential rights upon dissolution of shareholders whose preferential rights were superior to those receiving the dividend. In addition, our credit agreement does not permit us to pay dividends on our common stock.

Item 6. Selected Financial Data.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this Item.

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

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Results of Operations

Production

The following table presents the net quantities of oil, natural gas and natural gas liquids produced and sold by us for the years ended December 31, 2014, 2013 and 2012, and the average sales price per unit sold.

	Years Ended December 31,		
	2014	2013	2012
Production volumes:			
Crude oil and condensate (Bbl)	231,816	184,349	154,437
Natural gas (Mcf)	2,714,586	1,580,468	515,112
Natural gas liquids (Bbl)	97,783	51,875	9,571
Total (Boe) (1)	782,030	499,635	249,860
Average prices realized:			
Excluding commodity derivatives (both realized and unrealized):			
Crude oil and condensate (per Bbl)	$ 93.98	$ 104.26	$ 107.57
Natural gas (per Mcf)	$ 4.62	$ 3.83	$ 3.07
Natural gas liquids (per Bbl)	$ 38.44	$ 40.17	$ 42.67
Including commodity derivatives (realized only):			
Crude oil and condensate (per Bbl)	$ 91.74	$ 102.46	$ 106.45
Natural gas (per Mcf)	$ 4.32	$ 4.08	$ 4.07
Natural gas liquids (per Bbl)	$ 38.44	$ 40.17	$ 42.67

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (Boe).

Revenues

The following table presents our revenues for the years ended December 31, 2014, 2013 and 2012.

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Crude oil and condensate sales	$ 21,785,636	$ 19,220,185	$ 16,613,315
Natural gas sales	12,542,671	6,049,500	1,581,783
Natural gas liquids sales	3,758,875	2,083,905	408,389
Realized gain/(loss) on commodity derivatives	(1,326,467)	72,076	341,066
Unrealized gain/(loss) on commodity derivatives	4,724,985	(231,886)	1,256,918
Gas marketing sales	572,210	881,823	1,080,644
Other revenue	1,278,217	1,066,969	601,794
Total revenues	$ 43,336,127	$ 29,142,572	$ 21,883,909

Sale of Crude Oil and Condensate

Crude oil and condensate are sold through month-to-month evergreen contracts. The price for Louisiana production is tied to an index or a weighted monthly average of posted prices with certain adjustments for gravity, BS&W (Basic Sediment and Water) and transportation. Generally, the index or posting is based on WTI (West Texas Intermediate) and adjusted to LLS (Light Louisiana Sweet) or HLS (Heavy Louisiana Sweet). For the years ended December 31, 2014, 2013 and 2012, LLS postings averaged $3.02, $9.58 and $17.16 over WTI, respectively. Pricing for our California properties is based on an average of specified posted prices, adjusted for gravity, transportation, and for one field, a market differential.

Crude oil volumes sold increased by 25.7% for the year ended December 31, 2014 compared to the year ended December 31, 2013. New production from Bertha 8-3, Nettles 39-1 and the Pyramid wells was further enhanced by increased sales from DS&B 117, Crosby 12-1, Quinn 13-1, Starns 38-1 and Weyerhaeuser 57-3 after successful work-over operations. Increased net revenue interests on the La Posada wells were only partially offset by reduced production from Broussard No. 2 and Thibodeaux No. 1. Further reductions were due to the shut-in of the Main Pass 2 and Main Pass 4 wells for salt water disposal well work and declining production from Weyerhaeuser 9-1, Weyerhaeuser 57-2 and the Bakken wells in North Dakota. Realized crude oil prices experienced a 10.5% decrease from the year ended December 31, 2013 to the year ended December 31, 2014.

For the year ended December 31, 2013 compared to the same period of 2012, crude oil volumes increased by 19.4% as a result of new production at Broussard No. 1 and No. 2, Crosby 12-1, Starns 38-1 and the Addison acquisition properties, as well as increased production from the Bakken wells. These were partially offset by volume declines at Raccoon Island, DS&B 117 and Weyerhaeuser 57-3. A 3.7% realized price decrease during the same period was a further offset to the production increases.

Sale of Natural Gas and Natural Gas Liquids

Our natural gas is sold under multi-year contracts with pricing tied to either first of the month index or a monthly weighted average of purchaser prices received. Natural gas liquids are also sold under multi-year contracts usually tied to the related natural gas contract. Pricing is based on published prices for each product or a monthly weighted average of purchaser prices received.

For the year ended December 31, 2014 compared to the year ended December 31, 2013, a 71.8% increase in natural gas volumes sold was primarily due to increased production at Crosby 12-1 and the La Posada net revenue increases, partially offset by production declines at Broussard No. 2 and Thibodeaux No. 1. During the same period, realized natural gas prices increased by 5.9%.

For the year ended December 31, 2013, natural gas volumes increased 207% compared to the previous year, with La Posada, Crosby 12-1 and the Addison acquisition wells as the primary contributors. Average realized natural gas prices increased only slightly during the same period, from $4.07 in 2012 to $4.08 in 2013.

Increased natural gas sales at La Posada and Crosby 12-1 contributed to increased natural gas liquids (NGL) revenues, resulting in an 80.4% increase in natural gas liquids revenues for the year ended December 31, 2014 over the year ended December 31, 2013. The 410% increase in natural gas liquids for the year ended December 31, 2013 over the same period in 2012 was a result of the Addison acquisition, La Posada increased production and new production from the Crosby 12-1.

Gas Marketing

Gas marketing sales are natural gas volumes purchased from certain of our operated wells and the aggregated volumes sold with a mark-up of $.03 per MMBtu. Our wholly-owned subsidiary, Texas Southeastern Gas Marketing Company ("Marketing"), purchases and sells natural gas on our behalf and our working interest partners.

Expenses

Lease Operating Expenses

Our lease operating expenses ("LOE") and LOE per Boe for the years ended December 31, 2014, 2013 and 2012, are set forth below:

	Years Ended December 31,		
	2014	2013	2012
Lease operating expenses	$ 12,816,725	$ 9,316,364	$ 5,098,868
LOE per Boe	$ 16.39	$ 18.65	$ 20.41

LOE includes all costs incurred to operate wells and related facilities, both operated and non-operated. In addition to direct operating costs such as labor, repairs and maintenance, equipment rentals, materials and supplies, fuel and chemicals, LOE also includes severance taxes, product marketing and transportation fees, insurance, ad valorem taxes and operating agreement allocable overhead. LOE excludes costs classified as re-engineering and workovers. If severance and ad valorem taxes were not included in the above table, LOE would have been reduced by $3,741,513, $3,121,185 and $2,104,025 during the years ended December 31, 2014, 2013 and 2012, respectively, and operating costs per barrel of oil equivalent would have been reduced to $11.60, $12.40 and $11.99 for the years ended December 31, 2014, 2013 and 2012, respectively.

The 37.6% increase in LOE for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily due to maintenance projects at Raccoon Island, Crosby 21A-1 and Quinn 13-1; an increased working interest for the La Posada wells due to achieving payout; and LOE for the Crosby 12-1 well and the Pyramid properties. LOE per barrel of oil equivalent decreased by 12.1% for the same period generally due to increased sales volumes.

The Addison acquisition properties and new wells at Crosby 12-1 and Starns 38-1 caused an 82.7% increase in LOE for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The significant increase in sales volumes over the same period resulted in an LOE per barrel decrease of 8.6%.

Re-engineering and Workovers

Re-engineering and workover expenses include the costs to restore or enhance production in current producing zones as well as costs of significant non-recurring operations.

Workover expenses for the years ended December 31, 2014, 2013 and 2012 totaled $3,084,972, $2,521,707, and $433,599, respectively. Workover expenses increased in the year ended December 31, 2014 compared to the same period in 2013 due to work on the Gardner Island and Raccoon Island salt water disposal wells. The increase in workover expenses for the year ended December 31, 2013 compared to the same period in 2012 were primarily due to major re-engineering programs on our Livingston properties, the USA 34-1 well acquired from Addison, and the non-operated DS&B 117 well, in addition to non-recurring operation expenses for the Crosby 12-1 salt water disposal and costs to bring various Addison-acquired wells to producing standards.

General and Administrative Expenses

Our general and administrative ("G&A") expenses for the years ended December 31, 2014, 2013 and 2012, are summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
General and administrative:			
Stock-based compensation	$ 4,293,855	$ 589,164	$ -
Other	11,970,855	8,253,038	6,928,704
Capitalized	(3,442,095)	(2,786,669)	(2,589,342)
Net	$ 12,822,615	$ 6,055,533	$ 4,339,362

G&A expenses primarily consist of overhead expenses, employee remuneration and professional and consulting fees. We capitalize certain G&A expenditures where they satisfy the criteria for capitalization under GAAP as relating to oil and natural gas exploration activities following the full cost method of accounting.

For the year ended December 31, 2014, net G&A expenses were $6,767,082, or 112% over the amount for the prior year ended December 31, 2013. Stock-based compensation increased substantially over the prior year as a direct result of the closing of the merger. Over several years preceding the merger, we granted restricted stock awards dependent on the Company becoming a publically traded enterprise. Once that condition had been satisfied, we began amortizing the fair market value of these awards over the remaining service period required for vesting. This stock-based compensation, net of amounts capitalized, totaled $3,388,321 and $452,058 for fiscal years 2014 and 2013, respectively. Additionally, non-recurring professional costs associated with the merger and costs to explore other public listing options totaled $2,935,536 and $24,592 in fiscal years 2014 and 2013, respectively. Excluding these costs for prior stock-based compensation and the merger, along with Pyramid's 2014 G&A costs of $127,534, net G&A expenses for 2014 were $792,341, or 14%, over 2013. This increase was primarily the result of five (net) employee additions in 2014.

Excluding the net stock-based compensation and merger costs for 2013 mentioned above, G&A expenses for 2013 were $1,239,521, or 29%, higher than G&A expenses in 2012. An increase in salaries and overall headcount as well as other general overhead expenses accounted for this increase.

Depreciation, Depletion and Amortization

Our depreciation, depletion and amortization ("DD&A") for the years ended December 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
DD&A	$ 19,664,991	$ 12,077,368	$ 5,074,070

The net quantities of oil, natural gas and natural gas liquids produced and sold by us increased by 57% for the year ended December 31, 2014 compared to the year ended December 31, 2013, and increased by 100% for the year ended December 31, 2013 compared to the year ended December 31, 2012. This increase in production was the primary factor for the increase in DD&A in 2014 over 2013. See "Production" above for the volumes of oil, natural gas and natural gas liquids production.

DD&A for 2013 was up from 2012 primarily due to the Addison acquisition, which increased oil and gas properties before asset retirement obligations ("ARO") by $7,170,715. The increase to property for the Addison ARO was $6,043,412. Future development costs increased by $213,711,517 to $423,330,417, a 102% increase, largely due to 33 additional Addison PUD locations. Depletion per barrel went from $19.84 to $23.87. At January 1, 2013, the effective date of the Addison acquisition, the acquisition added 6,145 MBbls of oil, 17,130 MMcf of gas and 1,573 MBbls of natural gas liquids.

NON-GAAP FINANCIAL MEASURES

Adjusted EBITDA

The following table reconciles reporting net income to EBITDA and Adjusted EBITDA for the periods indicated:

	Years Ended December 31,		
	2014	2013	2012
Net Income (Loss)	$ (20,225,150)	$ (33,050,103)	$ (14,769,468)
Add: Depreciation, depletion & amortization of property and equipment	19,664,991	12,077,368	5,074,070
Add: Interest expense, net of interest income and amounts capitalized	302,568	560,340	201,945
Add (deduct): Income tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
EBITDA	(2,811,445)	(17,332,123)	(6,395,144)
Add: Costs to obtain a public listing	2,935,536	24,592	-
Add: Increase in value of preferred stock derivative liability	15,676,842	26,258,559	17,098,504
Add: Stock-based compensation net of capitalized cost	3,388,321	452,058	-
Add: Accretion of asset retirement obligation	604,511	668,497	265,323
Add: Bank mandated commodity derivative novation cost	-	175,000	-
Deduct: Amortization of benefit from commodity derivatives sold	(93,750)	(72,600)	(112,508)
Add (deduct): Net commodity derivatives mark-to-market loss (gain)	(4,724,985)	231,886	(1,256,918)
Adjusted EBITDA	$ 14,975,030	$ 10,405,869	$ 9,599,257

"EBITDA" represents earnings before interest, taxes, depreciation, depletion and amortization, and is a non-GAAP financial measure. Because the Company makes other adjustments to its EBITDA formula by considering the change in the preferred stock derivative liability, stock-based compensation net of capitalized cost, accretion of asset retirement obligations, costs to obtain a public listing, the merger costs, and changes in commodity derivative values, management refers to this metric as Adjusted EBITDA and it is provided as an additional metric that is used by the Company's board of directors and management to measure operating performance and trends. Adjusted EBITDA for the year ended December 31, 2014 increased from 2013 by $4,569,131 (44%) and from 2012 by $5,375,773 (56%), Adjusted EBITDA increased in 2013 from 2012 by $806,612 (8%).

Adjusted EBITDA is presented based on management's belief that it will enable a user of the financial information to understand the impact of these items on reported results. Additionally, this presentation provides a helpful comparison to similarly adjusted measurements of prior periods. Adjusted EBITDA is not a measure of financial performance under GAAP and should not be considered as an alternative to net income, earnings per share and cash flow from operations, as defined by GAAP. Adjusted EBITDA may not be comparable to similarly named non-GAAP financial measures that other companies may use and may not be useful in comparing the performance of those companies to the Company's performance.

Interest Expense

Our interest expense for the years ended December 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
Interest expense	$ 1,385,550	$ 1,599,492	$ 891,173
Interest capitalized	(1,059,350)	(1,031,816)	(681,090)
Net	$ 326,200	$ 567,676	$ 210,083
Bank debt	$ 22,900,000	$ 31,215,000	$ 17,875,000

Our line of credit was used to fund the $7.5 million purchase of the Addison acreage at the start of the 2013 second quarter. Debt increased again towards the end of 2013 to finance the drilling of the Crosby 12-1. Debt decreased in fiscal year 2014 when net proceeds from the sale of the issuance of the Series A Preferred Stock were used to pay down debt by $10.4 million during October 2014.

From September 2012 to May 2013, there was turnover in the participants of our syndicated bank credit facility which generated additional fees classified as interest expense, primarily during 2013. For a complete narrative of these costs and other bank administrative fees in interest expense, refer to Note L – Debt and Change in Banking Line and Agent Bank in the Notes to Consolidated Financial Statements included in this report.

Income Tax Expense

The following summarizes our income tax expense (benefit) and effective tax rates for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
Consolidated net income (loss) before income taxes	$ (22,779,004)	$ (29,969,831)	$ (11,671,159)
Income tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
Effective tax rate	11.21 %	(10.28)%	(26.55)%

Additionally, differences between the U.S. federal statutory rate of 35% and our effective tax rates are due to the tax effects of the excess of book carrying value over the tax basis in the full cost pool and the net operating loss carryforwards for each period. No tax benefit has been recognized for non-deductible expenses. Refer to Note O - Income Taxes in the Notes to Consolidated Financial Statements included in this report.

Liquidity and Capital Resources

Cash Flows

Our net increase in cash for the years ended December, 31, 2014, 2013 and 2012, is summarized as follows:

	Years Ended December 31,		
	2014	2013	2012
Cash flows provided by operating activities	$ 24,466,300	$ 14,912,903	$ 3,246,663
Cash flows used for investing activities	(18,088,363)	(27,253,041)	(28,762,394)
Cash flows provided by (used for) financing activities	985,874	11,249,627	29,879,721
Net increase (decrease) in cash	$ 7,363,811	$ (1,090,511)	$ 4,363,990

Cash Flows From Operating Activities

Cash flows from operations for the year ended December 31, 2014 increased by $9,553,397, or 64%, over fiscal year 2013 primarily due to increased working interest in the La Posada field, new production from the Bertha 8-3 and the Nettles 39-1, the addition of the California production after the merger, and increased production at the Crosby 12-1 and Quinn 13-1 wells. These increases were somewhat mitigated by higher lease operating expenses associated with increased production.

Cash flows from operations for the year ended December 31, 2013 increased by $11,666,240, or 359%, over fiscal year 2012, primarily due to new production at La Posada, the Addison acquisition, and the Bakken wells in North Dakota. These increases were partially offset by volume declines at Raccoon Island and increases in lease operating expenses associated with increasing production.

Cash Flows From Investing Activities

During the year ended December 31, 2014, the Greater Masters Creek Field accounted for $18,225,766 of our total oil and natural gas investing activities. Of that, $16,449,165 was spent to drill and complete the Crosby 14-1 well and its related salt water disposal well. The remaining $1,776,601 was spent on lease-related activities and preliminary costs for the next wells to be drilled in the field. At the Livingston 3D Project, $1,157,071 was spent to drill and complete the Nettles 39-1 well, along with $1,047,656 to drill the Blackwell 39-1, which was completed in the first quarter of 2015. Lease-related costs totaled $484,583. The Talbot 23-1 well in the Amazon 3D Project was spudded in early January 2015, and we incurred $364,411 in preliminary costs in 2014. Lease-related costs totaled $732,899. Additionally, $816,970 was spent evaluating and identifying development opportunities for our new producing properties in California. A net credit of $667,338 for insurance recovery on the Grief Bros. No. 1 created a credit balance for recompletions, capital workovers and P&A for the period ended December 31, 2014.

During 2013, we realized proceeds from the sale of interests in our projects and the sale of a salt water disposal well of $882,666. During 2012, we had proceeds of $1,386,649 from the sales of interests in our various projects including our Amazon 3-D Seismic Project, Tigre Lagoon 3-D Seismic Project, and several individual wells, including Piranha and Musial. During 2013, we completed the Addison acquisition of producing oil and natural gas properties including the assumption of certain liabilities for a cost of $7,350,000. During 2012, we completed two significant acquisitions, one non-operated joint venture of development acreage in the Bakken region of North Dakota for $4,175,000, and a second operated acreage position in the Greater Masters Creek Field of the Austin Chalk Trend in Central Louisiana for $8,891,134.

The following summarizes the expenditures for investing activities by type:

	Years Ended December 31,		
	2014	2013	2012
Acquisition of acreage and new properties	$ 4,924,999	$ 11,966,227	$ 18,830,912
Drilling and completion	19,537,826	11,788,741	11,668,105
Recompletions, capital workovers and plugging and abandoning (“P&A”)	(346,787)	2,412,658	978,364
Total oil and natural gas investing activities	24,116,038	26,167,626	31,477,381
Corporate office property and equipment purchases	100,812	80,507	319,249
Total cash used for capitalized expenditures on property and equipment	24,216,850	26,248,133	31,796,630
Proceeds from sale of property	(667,267)	(902,166)	(1,386,649)
Cash received in merger	(4,550,082)	-	-
Short-term investments retired	(2,125,541)	-	-
(Decrease) increase in noncurrent receivable from affiliate	(95,634)	2,493	2,486
Cash flows used in investing activities, including accounts payable	16,778,326	25,348,460	30,412,467
Change in capital expenditures financed by accounts payable	1,310,037	1,904,581	(1,650,073)
Cash flows used for investing activities	$ 18,088,363	$ 27,253,041	$ 28,762,394

Cash Flows From Financing Activities

Our cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Although we seek to mitigate this risk by hedging a significant portion of future crude oil and natural gas production out two years (three to five years historically), a significant deterioration in commodity prices negatively impacts revenues, earnings, and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactful as commodity prices in the short-term.

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, advances from our credit facility, sale of non-strategic assets, and the issuance of additional equity/debt securities. In addition, we may slow or accelerate our development of existing reserves to more closely match our projected cash flows.

On October 23 and 24, 2014, we issued 507,739 shares of Series A Preferred Stock in an underwritten public offering. The net proceeds to us from the offering of the Series A Preferred Stock were approximately $10.0 million, after deducting the underwriting discount and offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings under our credit facility.

At December 31, 2014, we had a $40.0 million conforming borrowing base with $22.9 million advanced, leaving an available borrowing capacity of $17.1 million. The borrowing base is currently undergoing review.

	Years Ended December 31,		
	2014	2013	2012
Credit Facility:			
Balances outstanding, beginning of year	$ 31,215,000	$ 17,875,000	$ 2,975,000
Activity	(8,315,000)	13,340,000	14,900,000
Balances outstanding, end of period	$ 22,900,000	$ 31,215,000	$ 17,875,000

Other than the credit facility, we had debt of $282,843, $178,027 and $183,601 at December 31, 2014, 2013 and 2012, respectively, from an installment loan financing oil and natural gas property insurance premiums. We had a cash balance of $11.6 million and short-term investments of $1.2 million at December 31, 2014.

Hedging Activities

Current Commodity Derivative Contracts

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

Fair Market Value of Commodity Derivatives

	December 31, 2014		December 31, 2013	
	Oil	Natural Gas	Oil	Natural Gas
Assets				
Current	$ 1,851,542	$ 1,486,995	$ -	$ -
Noncurrent	1,006,845	396,264	818,637	-
Liabilities				
Current	-	-	(423,217)	(253,915)
Noncurrent	-	-	-	(218,649)

Assets and liabilities are netted within each commodity on the balance sheet as all contracts are with the same counterparty. For the balances without netting, refer to Part II, Item 8. Notes to the Consolidated Financial Statements, Note H – Commodity Derivative Instruments.

The fair market value of our commodity derivative contracts in place at December 31, 2014 were net assets of $4,741,646.

We expect to reclassify losses on commodity derivatives of $33,249 net after taxes into earnings from accumulated other comprehensive income during the year ending December 31, 2015; however, actual cash settlement gains and losses recognized may differ materially.

See Part II, Item 8. Notes to the Consolidated Financial Statements, Note H – Commodity Derivative Instruments, for additional information on our commodity derivatives.

Hedging commodity prices for a portion of our production is a fundamental part of our corporate financial management. We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of our production. In implementing our hedging strategy we seek to:

- effectively manage cash flow to minimize price volatility and generate internal funds available for operations, capital development projects and additional acquisitions; and

- ensure our ability to support our exploration activities as well as administrative and debt service obligations.

Estimating the fair value of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices which, although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculation cannot be expected to represent exactly the fair value of our commodity derivatives. We currently obtain fair value positions from our counterparties and compare that value to the calculated value provided by our outside commodity derivative consultant. We believe that the practice of comparing the consultant's value to that of our counterparties, who are more specialized and knowledgeable in preparing these complex calculations, reduces our risk of error and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time.

Commitments and Contingencies

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

	Debt [(1)]	Asset for Commodity Derivatives [(2)]	Operating Leases	Asset Retirement Obligations
2015	$ 282,843	$ 3,338,537	$ 567,480	$ -
2016	-	1,403,109	575,868	-
2017	22,900,000	-	561,106	2,815,296
2018	-	-	2,264	766,911
2019	-	-	-	330,504
Thereafter	-	-	-	8,575,059
Totals	$ 23,182,843	$ 4,741,646	$ 1,706,718	$ 12,487,770

(1) Does not include future commitment fees, interest expense or other fees because our credit agreement is a floating rate instrument, and we cannot determine with accuracy the timing of future loans, advances, repayments or future interest rates to be charged.

(2) Represents the estimated future payments under our oil and natural gas derivative contracts based on the future market prices as of December 31, 2014. These amounts will change as oil and natural gas commodity prices change.

Off Balance Sheet Arrangements

We do not have any off balance sheet arrangements, special purpose entities, financing partnerships or guarantees (other than our guarantee of our wholly owned subsidiary's credit facility).

Critical Accounting Policies and Estimates

Critical accounting policies are defined as those that are reflective of significant judgments and uncertainties and that could potentially result in materially different results under different assumptions and conditions. See Note B – Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report, for a discussion of additional accounting policies and estimates made by management.

Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U. S. ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting policies are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Reserve Estimates

Our estimates of proved oil and natural gas reserves constitute those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal of such contracts is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulation by governmental agencies, and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic and therefore not includable in our reserve calculations. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and natural gas properties and/or the rate of depletion of such oil and natural gas properties.

Disclosure requirements under Staff Accounting Bulletin 113 ("SAB 113") include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average is also used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including dry hole costs, wells in progress, and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and natural gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated properties and our effective borrowing rate.

Capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is an impairment charge to income and a write-down of oil and natural gas properties in the quarter in which the excess occurs.

Given the volatility of oil and natural gas prices, it is probable that our estimate of discounted future net cash flows from estimated proved oil and natural gas reserves will change in the near term.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Hedging Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in the fair value of the derivative instruments are recorded in the income statement and included in sales of natural gas and crude oil.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX discount rates and price movements. The fair value of our commodity derivatives are calculated by our hedge counterparty and tested by an independent third party utilizing market-corroborated inputs that are observable over the term of the derivative contract.

Derivatives Associated with Preferred Stock

The Company issued Series A Preferred Stock on July 1, 2011 and Series B Preferred Stock in July and August of 2012. These shares of preferred stock had provisions with features of an option or derivative. Therefore, each quarter that these shares were outstanding required that this derivative liability be marked to fair value with the resulting changes recorded on the Consolidated Statement of Operations as “Change in fair value of preferred stock derivative liability – Series A and Series B.” Since the Company was not public at the time, this determination of fair value was performed with the use of a Monte Carlo option pricing model by an outside consulting firm using level 3 inputs, along with management estimates of the probability of various events.

Goodwill

We account for goodwill in accordance with ASC 350, Intangibles—Goodwill and Other (“ASC 350”). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have one reporting unit. Goodwill recorded on our financial statements is related to the merger with Pyramid in 2014.

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

Share-based Compensation

We have two types of long-term incentive awards – restricted stock awards (RSAs) and restricted stock units (RSUs). We account for them differently. RSUs are treated as a liability, although they are payable in either cash or stock at their vesting date, management intends to settle in cash, whereas RSAs are treated as equity since they are only payable in stock. The associated costs for RSUs are amortized as stock-based compensation over the life of the award. The costs associated with the RSAs are amortized from the point in time when the Company became public (RSAs had a performance-based requirement in order to vest).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this Item.

Item 8. Financial Statements and Supplementary Data.

The Report of the Independent Registered Public Accounting Firm and the Consolidated Financial Statements are set forth beginning on page F-1 of this Annual Report on Form 10-K and are included herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.

As previously reported on our Current Report on Form 8-K filed with the SEC on September 16, 2014 (the “prior 8-K”), on September 11, 2014, we dismissed our former independent registered public accounting firm and appointed Grant Thornton LLP as our independent registered public accounting firm for the 2014 fiscal year. For more information, please refer to the prior 8-K.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(e) and 15d-15(e), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were ineffective as of December 31, 2014 due to a material weakness in our internal control over financial reporting described below.

Management’s Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting of Yuma Energy, Inc. The Company’s internal control system was designed to provide reasonable assurance to management and the Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting practices.

All internal control systems, no matter how well designed, have inherent limitations. Because of these inherent limitations, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation, and may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In the course of preparing of our annual report on Form 10-K for the year ended December 31, 2014, we concluded that a material weakness in internal control over financial reporting existed as of December 31, 2014 as described below.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented, or detected and corrected on a timely basis.

We made an error in the application of GAAP regarding the timing and recognition of stock-based compensation charges. Specifically, we did not devote adequate time with regard to analysis of this complex area of accounting. We lacked adequate controls regarding specific training in the relevant accounting guidance, review and documentation of this area of GAAP accounting in relation to complex stock based accounting transactions and review of related accounting disclosures.

Plan for Remediation of this Material Weakness. We intend to send a member of our staff to professional seminars on this particular area of compensation accounting. We are designing additional controls around identification, analysis, documentation and application of technical accounting guidance with particular emphasis on stock-based compensation. These controls are expected to include the implementation of additional supervision and review activities by qualified personnel, the preparation of formal accounting memoranda to support our conclusions on technical accounting matters, the development and use of checklists and research tools and consultation with compensation accounting experts to assist in compliance with GAAP with regard to stock based accounting issues. We intend to complete the implementation of our remediation plan during fiscal 2015.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the three month period ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 11. Executive Compensation.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

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

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

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

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

Item 14. Principal Accounting Fees and Services.

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Shareholders.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

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

		Incorporated by Reference					
Exhibit No.	**Description**	**Form**	**SEC File No.**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
1.1	At-the-Market Issuance Sales Agreement dated December 19, 2014 between Yuma Energy, Inc. and MLV & Co. LLC.	8-K	001-32989	1.1	December 29, 2014		
2.1	Amended and Restated Agreement and Plan of Merger and Reorganization dated as of August 1, 2014, by and among Yuma Energy, Inc., Pyramid Oil Company, Pyramid Delaware Merger Subsidiary, Inc., and Pyramid Merger Subsidiary, Inc.	8-K	001-32989	2.1(A)	August 4, 2014		
3.1	Restated Articles of Incorporation dated September 10, 2014.	8-K	001-32989	3.1	September 16, 2014		
3.2	Certificate of Determination of Rights, Preferences, Privileges and Restrictions of 9.25% Series A Cumulative Redeemable Preferred Stock of Yuma Energy, Inc.	8-A	001-32989	3.2	October 20, 2014		
3.3	Amended and Restated Bylaws of Yuma Energy, Inc.	S-3	333-192094	4.2	November 5, 2013		
10.1	Credit Agreement dated as of August 11, 2011, among Yuma Exploration and Production Company, Inc., as Borrower, Amegy Bank National Association, as Administrative Agent, and each of the lenders from time to time party thereto.	S-4	333-197826	10.3	August 4, 2014		
10.1(a)	First Amendment and Limited Waiver to Credit Agreement and Assignment effective as of September 21, 2012, among Yuma Exploration and Production Company, Inc., as Borrower, Amegy Bank National Association, as Administrative Agent and Assignor, Union Bank, N.A., as an Assignee and successor Administrative Agent and successor Issuing Bank, and each of the lenders party thereto.	S-4	333-197826	10.4	August 4, 2014		
10.1(b)	Second Amendment to Credit Agreement and Assignment effective as of February 13, 2013, among Yuma Exploration and Production Company, Inc., as Borrower, Union Bank, N.A., as Administrative Agent and Assignor, Société Générale, as an Assignee and successor Administrative Agent and successor Issuing Bank, and each of the lenders party thereto.	S-4	333-197826	10.5	August 4, 2014		
10.1(c)	Third Amendment to Credit Agreement and Assignment effective as of May 20, 2013, among Yuma Exploration and Production Company, Inc., as Borrower, Union Bank, N.A., as Assignor, Société Générale, as an Assignor and Administrative Agent and Issuing Bank, OneWest Bank, FSB, as Assignee, and each of the lenders party thereto.	S-4	333-197826	10.6	August 4, 2014		
10.1(d)	Fourth Amendment to Credit Agreement effective as of April 22, 2014, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.	S-4	333-197826	10.7	August 4, 2014		
10.1(e)	Fifth Amendment to Credit Agreement effective as of October 14, 2014, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.	8-K	001-32989	10.1	October 14, 2014		

10.1(f)	Sixth Amendment to Credit Agreement effective as of January 23, 2015, among Yuma Exploration and Production Company, Inc., as Borrower, Société Générale, as Administrative Agent and Issuing Bank, and each of the lenders party thereto.	8-K	001-32989	10.1	January 29, 2014	
10.2†	Employment Agreement dated October 1, 2012, between Yuma Energy, Inc. and Sam L. Banks.	S-4	333-197826	10.8	August 4, 2014	
10.3†	Employment Agreement dated October 1, 2012, between Yuma Energy, Inc. and Michael F. Conlon.	S-4	333-197826	10.9	August 4, 2014	
10.4†	Employment Agreement dated June 15, 2014, between Yuma Energy, Inc. and Mark D. Hartman.	S-4	333-197826	10.10	August 4, 2014	
10.5	Form of Indemnification Agreement.	8-K	001-32989	10.1	September 16, 2014	
10.6†	Employment Agreement dated June 1, 2012, between Yuma Energy, Inc. and Kirk F. Sprunger.	8-K	001-32989	10.4	September 16, 2014	
10.7†	2006 Equity Incentive Plan of the Registrant.	S-8	333-175706	4.3	July 21, 2011	
10.8†	Yuma Energy, Inc. 2011 Stock Option Plan.	8-K	001-32989	10.5	September 16, 2014	
10.9†	Yuma Energy, Inc. 2014 Long-Term Incentive Plan.	8-K	001-32989	10.6	September 16, 2014	
10.10†	Employment Agreement dated October 15, 2014 between Yuma Energy, Inc. and Paul D. McKinney.	10-Q	001-32989		November 14, 2014	
10.11†	Separation Agreement and General Release of Claims dated December 25, 2014, between Yuma Energy, Inc. and Michael F. Conlon.	8-K	001-32989	10.1	December 29, 2014	
10.12†	Employment Agreement of John H. Alexander, dated February 21, 2002.	10-QSB	001-32989	10.4	March 29, 2002	
10.13†	Severance Award Agreement of John H. Alexander, dated January 9, 2007.	8-K	001-32989	99.1	January 16, 2007	
10.14†	Severance Award Agreement of John H. Alexander, dated December 30, 2008.	8-K	001-32989	10.1	January 6, 2008	
10.15†	Severance Award Agreement of John H. Alexander, dated June 4, 2009.	10-K	001-32989	10.4	March 30, 2011	
10.16†	Severance Award Agreement of John H. Alexander, dated September 21, 2010.	10-Q	001-32989	10.1	November 12, 2010	
10.17	Settlement Agreement and General Release of All Claims, dated as of September 30, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.1	October 4, 2013	
10.18	Trust Agreement, dated as of October 1, 2013, between the Registrant and Gilbert Ansolabehere, as trustee.	8-K	001-32989	10.2	October 4, 2013	
10.19	Consulting Agreement, dated as of October 1, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.3	October 4, 2013	

10.20	Indemnity Agreement, dated as of September 30, 2013, between the Registrant and John H. Alexander.	8-K	001-32989	10.4	October 4, 2013		
10.21	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Gary L. Ronning.	10-K	001-32989	10.10	March 31, 2014		
10.22	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Michael D. Herman.	10-K	001-32989	10.11	March 31, 2014		
10.23	Indemnity Agreement, dated as of January 7, 2014, between the Registrant and Rick D. Kasch.	10-K	001-32989	10.12	March 31, 2014		
10.24†	Amendment No. 1 dated March 12, 2015 to the Employment Agreement between Yuma Energy, Inc. and Paul D. McKinney.	8-K	001-32989	10.1	March 17, 2015		
14	Code of Ethics.	8-K	001-32989	14	September 16, 2014		
21.1	List of Subsidiaries.					X	
23.1	Consent of Grant Thornton LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
31.1	Certification of the Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
31.2	Certification of the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
32.2	Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
101.INS	XBRL Instance Document.					X	
101.SCH	XBRL Schema Document.					X	
101.CAL	XBRL Calculation Linkbase Document.					X	
101.DEF	XBRL Definition Linkbase Document.					X	
101.LAB	XBRL Label Linkbase Document.					X	
101.PRE	XBRL Presentation Linkbase Document.					X	

† Indicates management contract or compensatory plan or arrangement.

SIGNATURES

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

YUMA ENERGY, INC.

By: /s/ Sam L. Banks
Name: Sam L. Banks
Title: President and Chief Executive Officer
(Principal Executive Officer)

Date: March 30, 2015

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

Signature	Title	Date
/s/ Sam L. Banks Sam L. Banks	Chairman of the Board, Director, President and Chief Executive Officer (Principal Executive Officer)	March 30, 2015
/s/ Kirk F. Sprunger Kirk F. Sprunger	Chief Financial Officer, Treasurer and Corporate Secretary (Principal Financial Officer and Principal Accounting Officer)	March 30, 2015
/s/ James W. Christmas James W. Christmas	Director	March 30, 2015
/s/ Frank A. Lodzinski Frank A. Lodzinski	Director	March 30, 2015
/s/ Ben T. Morris Ben T. Morris	Director	March 30, 2015
/s/ Richard K. Stoneburner Richard K. Stoneburner	Director	March 30, 2015
/s/ Richard W. Volk Richard W. Volk	Director	March 30, 2015

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Yuma Energy, Inc.

We have audited the accompanying consolidated balance sheets of Yuma Energy, Inc. (the “Company”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Yuma Energy, Inc. as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas
March 30, 2015

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 11,558,322	$ 4,194,511
Short-term investments	1,170,868	-
Accounts receivable, net of allowance for doubtful accounts:		
Trade	9,739,737	10,837,211
Officers and employees	316,077	155,080
Other	697,991	417,850
Commodity derivative instruments	3,338,537	-
Prepayments	782,234	433,991
Deferred taxes	245,922	146,964
Other deferred charges	342,798	162,416
Total current assets	28,192,486	16,348,023
OIL AND GAS PROPERTIES (full cost method):		
Not subject to amortization	25,707,052	24,051,278
Subject to amortization	186,530,863	152,863,988
	212,237,915	176,915,266
Less: accumulated depreciation, depletion and amortization	(103,929,493)	(84,438,840)
Net oil and gas properties	108,308,422	92,476,426
OTHER PROPERTY AND EQUIPMENT:		
Land, buildings and improvements	2,795,000	-
Other property and equipment	3,439,688	2,066,760
	6,234,688	2,066,760
Less: accumulated depreciation and amortization	(1,909,352)	(1,822,925)
Net other property and equipment	4,325,336	243,835
OTHER ASSETS AND DEFERRED CHARGES:		
Commodity derivative instruments	1,403,109	818,637
Deposits	264,064	7,300
Receivables from affiliate	-	95,634
Goodwill	5,349,988	-
Other noncurrent assets	262,200	1,642,113
Total other assets and deferred charges	7,279,361	2,563,684
Total assets	$ 148,105,605	$ 111,631,968

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

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS - CONTINUED

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of debt	$ 282,843	$ 178,027
Accounts payable, principally trade	25,004,364	15,116,560
Commodity derivative instruments	-	677,132
Asset retirement obligations	-	1,755,650
Deferred taxes	471,995	-
Other accrued liabilities	1,419,565	1,127,283
Total current liabilities	27,178,767	18,854,652
LONG-TERM DEBT:		
Bank debt	22,900,000	31,215,000
OTHER NONCURRENT LIABILITIES:		
Preferred stock derivative liability, Series A and B	-	51,290,414
Asset retirement obligations	12,487,770	8,942,029
Commodity derivative instruments	-	218,649
Deferred taxes	14,388,662	13,160,205
Restricted stock units	71,569	102,532
Other	22,451	69,998
Total other noncurrent liabilities	26,970,452	73,783,827
PREFERRED STOCK:		
Series A and B, subject to mandatory redemption	-	35,666,342
EQUITY:		
Common stock, no par value		
(300 million shares authorized, 69,139,869 and 41,074,950 issued)	137,469,772	2,669,465
Preferred stock	9,958,217	-
Accumulated other comprehensive income	38,801	38,770
Accumulated earnings (deficit)	(76,410,404)	(50,596,088)
Total equity	71,056,386	(47,887,853)
Total liabilities and equity	$ 148,105,605	$ 111,631,968

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2014	2013	2012
REVENUES:			
Sales of natural gas and crude oil	$ 42,057,910	$ 28,075,603	$ 21,282,115
Other revenue	1,278,217	1,066,969	601,794
Total revenues	43,336,127	29,142,572	21,883,909
EXPENSES:			
Marketing cost of sales	1,045,177	1,234,308	891,118
Lease operating	12,816,725	9,316,364	5,098,868
Re-engineering and workovers	3,084,972	2,521,707	433,599
General and administrative – stock-based compensation	3,388,321	452,058	-
General and administrative – other	9,434,294	5,603,475	4,339,362
Depreciation, depletion and amortization	19,664,991	12,077,368	5,074,070
Asset retirement obligation accretion expense	604,511	668,497	265,323
Other	98,476	171,774	151,240
Total expenses	50,137,467	32,045,551	16,253,580
INCOME (LOSS) FROM OPERATIONS	(6,801,340)	(2,902,979)	5,630,329
OTHER INCOME (EXPENSE):			
Change in fair value of preferred stock derivative liability - Series A and Series B	(15,676,842)	(26,258,559)	(17,098,504)
Interest expense	(326,200)	(567,676)	(210,083)
Other, net	25,378	(240,617)	7,099
Total other income (expense)	(15,977,664)	(27,066,852)	(17,301,488)
NET LOSS BEFORE INCOME TAXES	(22,779,004)	(29,969,831)	(11,671,159)
Income tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
NET LOSS	(20,225,150)	(33,050,103)	(14,769,468)
PREFERRED STOCK:			
Dividends paid in cash, Series A perpetual preferred	224,098	-	-
Accretion (Series A and Series B)	786,536	1,101,972	963,900
Dividends paid in cash (Series A and Series B)	445,152	145,900	1,362,437
Dividends paid in kind (Series A and Series B)	4,133,380	5,412,281	-
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (25,814,316)	$ (39,710,256)	$ (17,095,805)
LOSS PER COMMON SHARE:			
Basic	$ (0.52)	$ (0.97)	$ (0.42)
Diluted	$ (0.52)	$ (0.97)	$ (0.42)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	49,678,444	41,074,953	40,896,222
Diluted	49,678,444	41,074,953	40,896,222

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2014	2013	2012
NET LOSS	$ (20,225,150)	$ (33,050,103)	$ (14,769,468)
OTHER COMPREHENSIVE INCOME (LOSS):			
Change in fair value of open commodity derivatives	-	-	1,075,885
Less income taxes	-	-	414,217
Change in fair value of open commodity derivatives, net of income taxes	-	-	661,668
Reclassification of (gain) loss on settled commodity derivatives	50	(374,099)	(527,117)
Less income taxes	19	(144,028)	(202,941)
Reclassification of (gain) loss on settled commodity derivatives, net of income taxes	31	(230,071)	(324,176)
OTHER COMPREHENSIVE INCOME (LOSS)	31	(230,071)	337,492
COMPREHENSIVE LOSS	$ (20,225,119)	$ (33,280,174)	$ (14,431,976)

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	December 31, 2014	2013	2012
COMMON STOCK:			
Balance at beginning of year (2012 as previously reported: 54,000 shares, $0.01 par value)	$ 2,669,465	$ 2,182,833	$ 540
Retroactive effect of change to no par value upon merger closing on 9/10/14	-	-	2,182,293
Retroactive effect of retirement of 54,000 Yuma Energy, Inc. shares of common stock outstanding before merger closing on 9/10/14	-	-	-
Retroactive effect of 40,896,221 shares issued for merger closing on 9/10/14	-	-	-
Convert Series A preferred stock to 15,112,295 shares of common stock on 9/10/14	71,028,086	-	-
Convert Series B preferred stock to 7,771,192 shares of common stock on 9/10/14	36,524,852	-	-
Pyramid Oil Company 4,788,085 shares outstanding last day of trading on 9/10/14	22,504,000	-	-
Fair value of Pyramid Oil Company stock options	100,500	-	-
Employee restricted stock awards (178,729 shares, vested 4/1/13, issued 9/11/14)	-	486,632	-
Employee restricted stock awards (107,291 shares, vested and issued 9/11/14)	488,615	-	-
Employee restricted stock awards forfeited 9/8/14 (87,851 shares vested 4/1/13)	-	-	-
Stock awards (100,000 shares) to employees, directors and consultants of Pyramid Oil Company vested upon the change in control and issued 9/11/14	501,000	-	-
Employee restricted stock awards (1,952,671 shares, not fully vested, amortized to equity from merger closing until vesting dates)	2,784,023	-	-
Employee restricted stock unit awards (273,907 shares, vested 12/31/14; 254,973 to be issued 4/1/15 and 18,934 to be issued 5/20/15)	869,231	-	-
Balance at end of period: 69,139,869 shares for 2014, 41,074,950 shares for 2013, and 40,808,370 shares for 2012, no par value	137,469,772	2,669,465	2,182,833
CAPITAL IN EXCESS OF PAR VALUE OF COMMON STOCK:			
Balance at beginning of 2012 as previously reported	-	-	2,182,293
Retroactive effect of September 10, 2014 change to no par value	-	-	(2,182,293)
Balance at end of period	-	-	-
PERPETUAL PREFERRED STOCK			
Balance at beginning of period	-	-	-
Issuance of 9.25% Series A cumulative redeemable preferred stock, no par value	9,958,217	-	-
Balance at end of period	9,958,217	-	-
ACCUMULATED OTHER COMPREHENSIVE INCOME:			
Balance at beginning of period	38,770	268,841	(68,651)
Comprehensive income (loss) from commodity derivative instruments, net of income taxes	31	(230,071)	337,492
Balance at end of period	38,801	38,770	268,841
ACCUMULATED EARNINGS (DEFICIT):			
Balance at beginning of period	(50,596,088)	(10,885,832)	6,209,973
Net loss attributable to Yuma Energy, Inc.	(20,225,150)	(33,050,103)	(14,769,468)
Series A perpetual preferred stock cash dividends	(224,098)	-	-
Preferred stock accretion (Series A and B)	(786,536)	(1,101,972)	(963,900)
Preferred stock cash dividends (Series A and B)	(445,152)	(145,900)	(1,362,437)
Preferred stock dividends paid in kind (Series A and B)	(4,133,380)	(5,412,281)	-
Balance at end of period	(76,410,404)	(50,596,088)	(10,885,832)
TOTAL EQUITY IN YUMA ENERGY, INC.	71,056,386	(47,887,853)	(8,434,158)
NONCONTROLLING PARTNERSHIP INTEREST			
Balance at beginning of period	-	-	241,938
Buy out partnership interests	-	-	(241,938)
Balance at end of period	-	-	-
TOTAL EQUITY	$ 71,056,386	$ (47,887,853)	$ (8,434,158)

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Reconciliation of net loss to net cash provided by operating activities			
Net loss	$ (20,225,150)	$ (33,050,103)	$ (14,769,468)
Increase in fair value of preferred stock derivative liability	15,676,842	26,258,559	17,098,504
Depreciation, depletion and amortization of property and equipment	19,664,991	12,077,368	5,074,070
Accretion of asset retirement obligation	604,511	668,497	265,323
Stock-based compensation net of capitalized cost	3,388,321	452,058	-
Amortization of other assets and liabilities	188,669	166,608	86,421
Deferred tax expense (benefit)	(2,553,854)	3,080,272	3,098,309
Bad debt expense	97,068	193,601	210,187
Write off deferred offering costs	1,257,160	-	-
Write off credit financing costs	-	313,652	30,000
Amortization of benefit from commodity derivatives (sold) and purchased, net	(93,750)	(72,600)	(112,508)
Net commodity derivatives mark-to-market (gain) loss	(4,724,985)	231,886	(1,256,918)
Other	5,448	(21,328)	(55,463)
Changes in current operating assets and liabilities:			
Accounts receivable	976,093	(5,589,741)	403,516
Other current assets	(267,386)	869,550	(689,537)
Restricted cash	-	-	341,474
Accounts payable	10,690,790	9,115,792	(6,420,733)
Other current liabilities	(170,921)	148,834	(56,514)
Other	(47,547)	69,998	-
NET CASH PROVIDED BY OPERATING ACTIVITIES	24,466,300	14,912,903	3,246,663

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

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS – CONTINUED

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on property and equipment	$ (25,526,887)	$ (28,152,714)	$ (30,146,557)
Proceeds from sale of property	667,267	902,166	1,386,649
Cash received from merger	4,550,082	-	-
Short-term investments retired	2,125,541	-	-
Decrease (increase) in noncurrent receivable from affiliate	95,634	(2,493)	(2,486)
NET CASH USED IN INVESTING ACTIVITIES	(18,088,363)	(27,253,041)	(28,762,394)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowing	901,257	872,754	606,238
Payments on borrowings	(796,441)	(878,328)	(659,101)
Change in borrowing on line of credit	(8,315,000)	13,340,000	14,900,000
Line of credit financing costs	(92,909)	(681,739)	(280,166)
Net proceeds from issuance of preferred stock	9,958,217	-	-
Deferred offering costs	-	(1,257,160)	17,183,705
Cash dividends to preferred stockholders	(669,250)	(145,900)	(1,362,437)
Buy-out Yuma Production 1985, Ltd. minority interest partners	-	-	(245,422)
Derivative instruments purchased	-	-	(16,004)
Decrease in noncurrent payable to affiliate	-	-	(247,092)
NET CASH PROVIDED BY FINANCING ACTIVITIES	985,874	11,249,627	29,879,721
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	7,363,811	(1,090,511)	4,363,990
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,194,511	5,285,022	921,032
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 11,558,322	$ 4,194,511	$ 5,285,022
Supplemental disclosure of cash flow information:			
Interest payments (net of interest capitalized)	$ 175,009	$ 22,210	$ 160,720
Interest capitalized	$ 1,059,350	$ 1,031,816	$ 681,090
Supplemental disclosure of significant non-cash activity:			
Preferred dividends paid in kind (Series A and Series B)	$ 4,133,380	$ 5,412,281	$ -
Change in capital expenditures financed by accounts payable	$ 1,310,037	$ 1,904,581	$ (1,650,073)

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

NOTE A – ORGANIZATION, CONSOLIDATION AND NATURE OF BUSINESS

Yuma Energy, Inc., a California corporation ("YEI" and collectively with its subsidiaries, the "Company") (formerly Pyramid Oil Company ("Pyramid")), is a U.S.-based oil and gas company focused on the exploration for, and development of, conventional and unconventional oil and gas properties, primarily through the use of 3-D seismic surveys, in the U.S. Gulf Coast and California.

On September 10, 2014, a wholly owned subsidiary of the Company merged with and into Yuma Energy, Inc., a Delaware corporation ("Yuma Co."), in exchange for 66,336,701 shares of the Company's common stock, and the Company subsequently changed its name from "Pyramid Oil Company" to "Yuma Energy, Inc." which we refer to as the "merger". As a result of the merger, the former Yuma Co. stockholders held approximately 93%, of the then-outstanding common stock of the Company, and thus acquired voting control. Although Pyramid was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of Pyramid by Yuma Co. See Note M – Merger with Pyramid Oil Company and Goodwill for additional information.

Simultaneously with the closing of the merger, Yuma Co. changed its name to "The Yuma Companies, Inc." In addition, a subsidiary of the Company, Pyramid Oil LLC, a California limited liability company, was formed to hold Pyramid's oil and natural gas properties.

The Consolidation

YEI was incorporated on October 9, 1909 and has six subsidiaries as listed below. Their financial statements are consolidated with those of YEI.

Company name	Reference	State of incorporation	Date of incorporation
The Yuma Companies, Inc.	"YCI"	Delaware	10/30/96
Yuma Exploration and Production Company, Inc.	"Exploration"	Delaware	01/16/92
Yuma Petroleum Company	"Petroleum"	Delaware	12/19/91
Texas Southeastern Gas Marketing Company	"TSM"	Texas	09/12/96
Pyramid Oil LLC	"POL"	California	08/08/14
Pyramid Delaware Merger Subsidiary, Inc.	"PDMS"	Delaware	02/04/14

YCI and PDMS are wholly owned subsidiaries of YEI, and YCI is the parent corporation of Exploration, Petroleum, TSM and POL.

Exploration identifies and captures economic deposits of hydrocarbons by using: (i) 3-D seismic imaging and other advanced technologies, with an emphasis on acquiring proprietary 3-D seismic to systematically explore, exploit and develop onshore and offshore crude oil and natural gas provinces; (ii) unconventional oil resource plays; and (iii) high impact deep structural prospects located beneath known producing trends. This approach is bolstered by strategic producing property acquisitions. Historically, Exploration has sold working interests in prospects to industry partners on traditional terms. Exploration's operations are primarily conducted in the Gulf Coast region, with the Company having interests in approximately 300 wells.

Petroleum became relatively inactive during 1998 due to the transfer of substantially all exploration and production activities to Exploration.

TSM is primarily engaged in the marketing of natural gas in Louisiana.

POL and PDMS were inactive during 2014 (see Note W – Subsequent Events).

NOTE B – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

1. Basis of Presentation

The accompanying financial statements include the accounts of YEI on a consolidated basis. All significant intercompany accounts and transactions between YEI, YCI, Exploration, Petroleum, TSM and POL have been eliminated in the consolidation. All events described or referred to as prior to September 10, 2014 relate to Yuma Co. as the accounting acquirer. All references to "Pyramid" refer to the Company prior to the closing of the merger on September 10, 2014.

The companies maintain their accounts on the accrual method of accounting in accordance with United States Generally Accepted Accounting Principles ("GAAP"). Each of the Companies has a fiscal year ending December 31.

2. Management's Use of Estimates

In preparing financial statements in conformity with GAAP, management is required to make informed estimates and assumptions with consideration given to materiality. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the reporting period. Actual results could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include: estimates of proved reserves and related estimates of the present value of future net revenues; the carrying value of oil and gas properties; estimates of fair value; asset retirement obligations; income taxes; derivative financial instruments; valuation allowances for deferred tax assets; uncollectible receivables; useful lives for depreciation; future cash flows associated with assets; obligations related to employee benefits; and legal and environmental risks and exposures.

3. Reclassifications

When required for comparability, reclassifications are made to the prior period financial statements to conform to the current year presentation.

4. Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – inputs that are not observable from objective sources, such as the Company's internally developed assumptions about market participant assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair value measurement.)

In determining fair value, the Company utilizes observable market data when available, or models that utilize observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

If the inputs used to measure the financial assets and liabilities fall within more than one level described above, the category is based on the lowest level input that is significant to the fair value measurement of the instrument (see Note G – Fair Value Measurements).

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reported on the balance sheet approximates fair value.

Nonfinancial assets and liabilities initially measured at fair value include asset retirement obligations and exit or disposal costs.

Level 3 Valuation Techniques – Financial assets are considered Level 3 when their fair values are determined using pricing models, discounted cash flow methodologies or similar techniques and at least one significant model assumption or input is unobservable. Level 3 financial liabilities consist of the Series A Preferred Stock issued July 1, 2011, and the Series B Preferred Stock issued July and August of 2012, for which there was no current market for these securities and such that the determination of fair value required significant judgment or estimation. The Company has historically valued certain possible financial scenarios relating to its preferred and common stock securities prior to being publicly traded using a Monte Carlo simulation model with the assistance of an independent valuation consultant. Prior to being publicly traded, the Company's preferred stock securities had certain provisions, including automatic conditional conversion, re-pricing/down-round, change of control, default and follow-on offering that necessitated financial modeling. These models incorporated transaction details such as the stock price of comparable companies in the same industry, contractual terms, maturity, and risk free interest rates, as well as assumptions about future financings, volatility, and holder behavior as of issuance, and each quarter thereafter (see Note I – Preferred Stock).

5. **<u>Statement of Cash Flow</u>**

Cash on hand, deposits in banks and short-term investments with original maturities of three months or less are considered cash and cash equivalents. The cash flow of a derivative instrument of an identifiable transaction is classified in the same category as the cash flow from the item being hedged.

6. **<u>Short-term Investments</u>**

Short-term investments consist of commercial bank certificates of deposit maturing in May 2015 and are valued at cost.

7. **<u>Trade Receivables</u>**

Accounts receivable are stated net of allowance for doubtful accounts of $138,960 and $55,000 at December 31, 2014 and 2013, respectively.

Management evaluates accounts receivable quarterly on an individual account basis, making individual assessments of collectability, and reserves those amounts it deems potentially uncollectible.

8. **<u>Natural Gas Imbalances</u>**

Pipeline gas imbalances represent the differences in measured volumes between gas receipts from suppliers and/or transporters and gas deliveries to end users, transporters and/or other purchasers. Most imbalances are settled monthly through cash-out mechanisms provided for in sales and transportation contracts. Other imbalances are carried forward until over or under deliveries in succeeding months can offset them. Gas imbalances are valued at cost utilizing the weighted average method.

Exploration utilizes the sales method to account for natural gas production volume imbalances. Under this method, income is recorded based on Exploration's net revenue interest in production taken for delivery. At December 31, 2014, Exploration had a net payable of approximately 23,248 Mcf under various natural gas balancing agreements, as compared to a 23,669 Mcf net payable at December 31, 2013.

9. Inventories

Inventories, consisting principally of oilfield equipment, are carried at the lower of cost or market. The Company will often have tangible materials purchased for a well carried for the joint account (oil and gas property full cost pool on the balance sheet) pending sale or disposition.

10. Derivative Instruments

All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in the Company's Consolidated Balance Sheets as either an asset or liability and measured at fair value. Changes in the derivative instrument's fair value are recognized currently in earnings, unless the derivative instrument was designated as a cash flow hedge. Under cash flow hedge accounting, unrealized gains and losses were reflected in stockholders' equity as accumulated other comprehensive income ("AOCI") to the extent they were effective until the forecasted transaction occurred. The Company discontinued cash flow hedge accounting effective January 1, 2013. The result of this change in policy was that the amount carried in AOCI at December 31, 2012 was amortized to oil and gas revenues during the month the hedges settle. Subsequent to December 31, 2012, all hedges are treated as non-qualifying derivative instruments and all new mark-to-market adjustments are in "Sales of natural gas and crude oil" in the Consolidated Statements of Operations.

For cash flow hedge accounting, a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in derivative instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. When using hedge accounting, hedge effectiveness is assessed quarterly based on total changes in the derivative instrument's fair value by performing regression analysis. A hedge is considered effective if certain statistical tests are met. The Company recorded hedge ineffectiveness in "Sales of natural gas and crude oil" in the Consolidated Statements of Operations.

11. Oil and Natural Gas Properties

Investments in oil and natural gas properties are accounted for using the full cost method of accounting. Under this method, all costs directly related to the acquisition, exploration, exploitation and development of oil and natural gas properties are capitalized.

Costs of reconditioning, repairing, or reworking of producing properties are expensed as incurred. Costs of workovers adding proved reserves are capitalized. Projects to deepen existing wells, recomplete to a shallower horizon, or improve (not restore) production to proved reserves are capitalized.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. Abandonments of properties are accounted for as adjustments of capitalized costs with no loss recognized.

Depreciation, Depletion and Amortization – The capitalized cost of oil and natural gas properties, excluding unevaluated properties, is amortized using the unit-of-production method (equivalent physical units of 6 Mcf of natural gas to each barrel of oil equivalent, or "Boe") using estimates of proved reserve quantities. Investments in unproved properties are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of the assessment indicate that the properties are impaired, the amount of impairment is added to the proved oil and gas property costs to be amortized. The amortizable base includes future development, abandonment and restoration costs. The rate for depreciation, depletion and amortization ("DD&A" or "depletion") per Boe for the Company was $24.92, $23.87 and $19.84 for fiscal years 2014, 2013 and 2012, respectively. DD&A expense for oil and natural gas properties was $19,490,653, $11,927,872 and $4,956,196 for fiscal years 2014, 2013 and 2012, respectively.

Impairments – Total capitalized costs of oil and gas properties are subject to a limit, or so-called "ceiling test." The ceiling test limits total capitalized costs less related accumulated DD&A and deferred income taxes to a value not to exceed the sum of (i) the present value, discounted at a ten percent annual interest rate, of future net revenue from estimated production of proved oil and gas reserves, including the impact of cash flow hedges, based on current economic and operating conditions less future development costs (excluding retirement costs); plus (ii) the cost of properties not subject to amortization; less (iii) income tax effects related to differences in the book and tax basis of oil and gas properties. If unamortized capitalized costs less related deferred income taxes exceed this limit, the excess is charged to DD&A in the quarter the assessment is made. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. These net unamortized costs, tested each calendar quarter, have not exceeded the cost center ceiling for fiscal years 2014, 2013 and 2012.

Oil and natural gas properties not subject to amortization consist of undeveloped leaseholds and exploratory and developmental wells in progress before the assignment of proved reserves. Management reviews the costs of these properties periodically for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in impairment assessments include drilling results by the Company and other operators, the terms of oil and gas leases not held for production, and available funds for exploration and development.

The table below shows the cost of unproved properties, along with well and development costs in progress not subject to amortization at December 31, 2014, and the year in which those costs were incurred.

	Year of acquisition				
	2014	2013	2012	Prior	Total
Leasehold acquisition cost	$ 154,194	$ 1,704,190	$ 15,349,192	$ 3,897,844	$ 21,105,420
Exploration and development cost	891,610	1,059,262	111,910	71,455	2,134,237
Capitalized interest	609,970	829,456	670,190	357,779	2,467,395
Total	$ 1,655,774	$ 3,592,908	$ 16,131,292	$ 4,327,078	$ 25,707,052

Capitalized Interest – Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $1,059,350, $1,031,816 and $681,090 of interest associated with the line of credit (see Note L – Debt and Change in Banking Line and Agent Bank) during fiscal years 2014, 2013 and 2012, respectively. The capitalization rates are based on the Company's weighted average cost of borrowings used to finance prospect generation.

Capitalized Internal Costs – Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by the Company for its own account, and that are not related to production, general corporate overhead or similar activities, are also capitalized. The Company capitalized $3,442,095, $2,702,952 and $2,589,342 of allocated indirect costs, excluding interest, related to these activities during fiscal years 2014, 2013 and 2012, respectively.

The Company develops oil and natural gas drilling projects called "prospects" by industry participants and markets participation in these projects. In doing this, the Company typically earns a profit over its actual costs in seismic, land, brokerage, brochuring and marketing. It typically markets interests in the project on a "third for a quarter" basis, whereby the participant pays a percentage of the cost to casing point or through prospect payout and then has its participation interest reduced by twenty-five percent (25%) with the Company earning the difference. This difference is referred to as the "carried interest."

The Company assembles 3-D seismic survey projects and markets participating interests in the projects. The Company typically recovers all of its costs plus allocated overhead, and receives a quarterly general and administrative ("G&A") expense reimbursement paid by the various participants in the project during the 3-D seismic acquisition phase and the 3-D seismic interpretation phase. The proceeds from the sale of the 3-D seismic survey along with the quarterly G&A reimbursements are included in the full cost pool caption "Not subject to amortization." In addition, the participants in the 3-D seismic survey typically carry the Company for a percentage of the costs associated with the 3-D survey acquisition, ranging from 25 to 35 percent. The Company received G&A expense reimbursements of $-0-, $42,329 and $172,173 in fiscal years 2014, 2013 and 2012, respectively.

12. Other Property and Equipment

Other property and equipment is recorded at cost with Pyramid property acquired in the merger marked to fair value as of the closing date of the merger. Expenditures for major additions and improvements are capitalized, while maintenance, repairs and minor replacements which do not improve or extend the life of such assets are charged to operations as incurred. Property and equipment sold, retired or otherwise disposed of are removed at cost less accumulated depreciation, and any resulting gain or loss is reflected in "Other" in "Total Expenses" in the accompanying Consolidated Statements of Operations.

Office business machines and furniture and fixtures are depreciated using the modified accelerated cost recovery system ("MACRS") for financial reporting purposes. MACRS depreciation methods approximate depreciation expense computed under GAAP using the double declining balance method.

Depreciation of drilling and operating equipment, automotive, and buildings are computed using the straight-line method over the shorter of the estimated useful lives or the applicable lease terms.

Leasehold improvements for the corporate office space in Houston, Texas are depreciated by the straight line method over the term of the lease.

	Estimated useful life in years	December 31, 2014	December 31, 2013
Land	n/a	$ 2,469,000	$ -
Office business machines	3 - 5	1,361,149	1,350,568
Drilling and operating equipment	14	982,010	-
Furniture and fixtures	7	412,215	383,585
Automotive	5	351,707	-
Office leasehold improvements	5	332,607	332,607
Buildings and improvements	3 - 25	326,000	-
Total other property and equipment		6,234,688	2,066,760
Less: Accumulated depreciation and leasehold improvement amortization		(1,909,352)	(1,822,925)
Net book value		$ 4,325,336	$ 243,835

Depreciation and leasehold improvement amortization expense totaled $174,338, $149,496 and $117,874 for the years ended December 31, 2014, 2013 and 2012, respectively.

13. Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. The provisions of Accounting Standards Codification ("ASC") 350, Intangibles – Goodwill and Other ("ASC 350") requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment, or more frequently if events occur or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. However, the Company has only one reporting unit. To assess impairment, the Company has the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the book value. Absent a qualitative assessment, or, through the qualitative assessment, if the Company determines it is more likely than not that the fair value of the reporting unit is less than the book value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the book value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. The Company's goodwill as of December 31, 2014 relates to its acquisition of Pyramid. Refer to Note M – Merger with Pyramid Oil Company and Goodwill for more details regarding the merger. The Company performs its goodwill impairment test annually, using a measurement date of July 1, or more often if circumstances require.

14. Accounts Payable

Accounts payable consist principally of trade payables and costs associated with oil and natural gas exploration.

15. Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources, along with liabilities for environmental remediation or restoration claims, are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Expenditures related to environmental matters are expensed or capitalized in accordance with the Company's accounting policy for property and equipment.

16. Revenue Recognition

Revenue is recognized by the Company when deliveries of crude oil, natural gas and condensate are delivered to the purchaser and title has transferred. Crude oil sales in Louisiana, representing a significant portion of the Company's production, are typically indexed to Light Louisiana Sweet ("LLS"). TSM recognizes revenue from sales of natural gas primarily to other marketing companies and industrials in the period in which the natural gas is delivered and billed to the customer. Sales are based on index prices per MMBtu or the daily "spot" price as published in national publications with a mark-up or mark-down defined by contract with each customer.

17. Income Taxes

The Company files a consolidated federal tax return. Deferred taxes have been provided for temporary timing differences. These differences create taxable or tax-deductible amounts for future periods (see Note O – Income Taxes).

18. Other Taxes

Taxes incurred, other than income taxes, are as follows:

	December 31,		
	2014	2013	2012
Production and severance tax	$ 2,693,396	$ 2,403,263	$ 2,002,397
Ad valorem tax	1,046,134	732,302	114,261
Sales tax	62,864	180,498	40,146
State franchise taxes	40,740	41,072	2,390
Total	$ 3,843,134	$ 3,357,135	$ 2,159,194

The Company reports oil and natural gas sales on a gross basis and, accordingly, includes net production, severance, and ad valorem taxes on the accompanying Consolidated Statements of Operations as a component of lease operating expenses. Sales taxes are collected from customers on sales of natural gas by TSM, and remitted to the appropriate state agency. Exploration accrues sales tax on applicable purchases of materials, and remits funds directly to the taxing jurisdictions.

19. Financial Instruments

The Company's financial instruments consist of cash, receivables, payables, long-term debt, oil and natural gas derivatives, and (prior to the merger as described in Note M – Merger with Pyramid Oil Company and Goodwill) Series A and Series B Preferred Stock. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of these items. The carrying amount of long-term debt as of December 31, 2014 and 2013 approximates fair value because the interest rate on this obligation is variable. The fair value of the oil and natural gas derivative instruments is included below in Note H – Commodity Derivative Instruments. The embedded derivative associated with each of the Series A and Series B Preferred Stock (eliminated in the merger) was bifurcated and carried at fair value as further described in Note I – Preferred Stock.

20. Accumulated Other Comprehensive Income

AOCI includes changes in equity that are excluded from the Consolidated Statements of Operations and were recorded directly into a separate section of equity on the Consolidated Balance Sheets. The Company's AOCI shown on the Consolidated Balance Sheets and the Consolidated Statements of Changes in Equity consists of unrealized income and losses on cash flow hedges; however, the Company discontinued hedge accounting effective January 1, 2013. AOCI is now comprised of the balance as of December 31, 2012 for the derivative instruments that qualified for hedge accounting at that time less those contracts that have subsequently expired. AOCI will continue to be adjusted for the contracts as they settle.

21. General and Administrative Expenses – Stock-Based Compensation

This includes payments to employees in the form of restricted stock awards, restricted stock units and stock options. As such, these amounts are non-cash Company stock-based awards.

The Company adopted the 2011 Stock Option Plan on June 21, 2011, and the 2014 Long-Term Incentive Plan effective September 10, 2014 (see Note N – Stockholders' Equity). The Company adopted an Annual Incentive Plan for fiscal years 2014 and 2013 (see Note Q – Employee Benefit Plans).

The Company accounts for stock-based compensation at fair value. The Company grants equity-classified awards including stock options and vested and non-vested equity shares (restricted stock awards and units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of common stock.

The Company records compensation cost, net of estimated forfeitures, for non-vested stock units over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See Note J – Stock-Based Compensation.

22. General and Administrative Expenses - Other

G&A expenses are reported net of amounts capitalized pursuant to the full cost method of accounting.

Reimbursements of G&A expenses, if received from working interest owners of producing oil and natural gas properties operated by the Company (COPAS, or Council of Petroleum Accountants Societies, overhead), are reported as a reduction to G&A expense. Reimbursements of G&A expenses, if received from joint venture participants in 3-D seismic acquisition surveys, are initially reported as a reduction of capitalized G&A expenses on the Consolidated Balance Sheets in the full cost pool caption "Not subject to amortization".

23. Re-engineering and Workovers

One of the Company's core business strategies is to perform a comprehensive field re-engineering and design to increase and maintain production, lower per-unit operating expenses, and improve field economics. Re-engineering projects are undertaken with the intent of lowering per-unit operating expenses and/or reducing field down-time. In addition, the Company seeks to implement more efficient production practices in order to increase production and/or arrest natural field production declines. These practices are often deployed in fields in connection with or in anticipation of further field development activities such as installation of secondary recovery operations or additional drilling. Workovers included within this category relate to significant non-recurring operations.

24. Other Noncurrent Assets

Included in the 2013 noncurrent assets are deferred offering costs. During 2013, the Company explored several options to go public, including a possible listing on the Australian Stock Exchange. To accomplish this, the Company engaged legal, accounting, and reserve engineering specialists to assist in this process. These costs were charged to G&A during the first quarter of 2014.

25. Earnings per Share

The Company's basic earnings per share ("EPS") is computed based on the average number of shares of common stock outstanding for the period. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and performance-based stock awards, if the inclusion of these items is dilutive. See Note N – Stockholders' Equity.

26. Changes in Accounting Principles

Not Yet Adopted

The Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers*. This ASU supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities – Oil and Gas – Revenue Recognition*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

ASU 2014-08, R*eporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* changes the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. This ASU is effective beginning in 2015, with early adoption permitted for disposals or for assets classified as held for sale not reported in previously issued financial statements. Management does not believe that the adoption of this ASU will have a significant impact on the Company's consolidated results of operations, financial position or cash flows.

Recently adopted

In June 2013, FASB ratified the Emerging Issues Task Force consensus which requires that an unrecognized tax benefit (or a portion thereof) be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update was effective for the Company beginning with the first quarter of 2014 and was applied prospectively to unrecognized tax benefits that existed as of the effective date. Adoption of this accounting standards update did not have a significant impact on the Company's consolidated results of operations, financial position or cash flows.

In February 2013, an ASU was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, which are separately addressed within GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This ASU was effective for the Company beginning in the first quarter of 2014 and was applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that existed at the beginning of 2014. Adoption of this ASU did not have a significant impact on the Company's consolidated results of operations, financial position or cash flows.

NOTE C – ADDISON ACQUISITION

On April 5, 2013, the Company acquired from Addison Oil, L.L.C. ("Addison") approximately 51,460 net acres held by production in the Austin Chalk adjacent to 25,926 net acres held by the Company at that time. This acquisition increased the Company's acreage holdings in the Austin Chalk to over 77,000 net acres at the time of closing. The purchase price was $7.5 million, with an effective date of January 1, 2013. The Company granted a two percent overriding royalty to the sellers, and sellers have a right to participate in new wells or new side tracks for a twenty-five percent (25%) working interest. This acquisition complemented the Company's existing acreage position and substantially increased the Company's number of proved undeveloped drilling locations and proved reserve values.

Associated with this acquisition, the Company recorded $6,043,412 for the associated future asset retirement obligations and $1,440,702 in suspended royalty and revenue obligations, net of related receivables.

NOTE D – ASSET RETIREMENT OBLIGATIONS

The Company records the cost of obligations associated with the retirement of tangible long-lived assets at fair value when the asset is acquired. The asset retirement obligations ("ARO's") are recorded as liabilities and the associated costs are capitalized as part of the related long-lived assets and then depreciated over the remaining useful lives. Changes in the liabilities resulting from the passage of time are recognized as operating (accretion) expenses and are allocated using the interest method. For the Company, ARO's relate to the abandonment of oil and gas producing facilities.

Since the Company uses the full cost method, settlement recognition is impacted. If a liability is settled for an amount other than the recorded amount, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. In addition, the Company carries ARO assets on the balance sheet as part of its full cost pool, and includes these ARO assets in its amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

The net increase to ARO during 2013 from the Addison acquisition was $6,043,412. An initial Addison ARO estimate of $10,967,986 was recorded in the second quarter of 2013, but the lives and costs were reevaluated later that year with a resulting reduction of $4,924,574.

<u>Asset Retirement Obligations</u>

	December 31, 2014	December 31, 2013
Beginning of year balance	$ 10,697,679	$ 4,233,782
Pyramid liabilities assumed in the merger	943,951	-
Liabilities incurred during year	416,162	11,178,614
Liabilities settled during year	-	(1,278,774)
Accretion expense	604,511	668,497
Revisions in estimated cash flows	(174,533)	(4,104,440)
End of year balance	$ 12,487,770	$ 10,697,679

NOTE E – RECEIVABLES AND PAYABLES WITH AFFILIATES, CHIEF EXECUTIVE OFFICER AND EMPLOYEES

The following table provides information with respect to related party transactions with affiliates, the Chief Executive Officer ("CEO") of the Company, and employees. The trade receivable from the CEO is for invoiced costs on prospects and wells (see Note F – Related Party Transactions).

	December 31,	
	2014	2013
Receivables from affiliates, CEO and employees:		
Current:		
Yuma CEO*	$ 174,720	$ 135,080
Employees	141,357	20,000
	316,077	155,080
Noncurrent:		
Yuma Gas Corporation	-	95,634
Total	$ 316,077	$ 250,714

*CEO paid balances outstanding at December 31, 2014; balance represents December 2014 charges billed subsequent to year-end under accrual accounting.

NOTE F – RELATED PARTY TRANSACTIONS

Chief Executive Officer

Effective August 15, 2011, the Company entered into a Working Interest Incentive Plan ("WIIP") with the Company's CEO, Sam L. Banks. Under the WIIP, Mr. Banks may purchase:

- Working interests in prospects from the Company or from unaffiliated third parties up to 2.5% of the Company's working interest; and
- Working interests in production acquisitions that the Company undertakes in an amount up to 5% of the aggregate cost of the interest to be acquired.

The purchase price for any working interests acquired from the Company is no better than the terms agreed to by unaffiliated third parties.

Working interests acquired during fiscal years 2014 and 2013 under the WIIP are listed below:

Year	Well, prospect or project	Working interest	Amount paid
2014	Anaconda Prospect	1.95000%	$ 16,900
2014	Gardner Island Well &	1.43600%	
	Main Pass 4 Facility	1.85500%	$ 78,988
2014	Austin Chalk (Additional W.I.)	1.00000%	$ 16,000
2013	Bell City East Prospect	.71063%	$ 5,330
2013	Austin Chalk	1.00000%	$ 9,412
2013	Addison Acquisition	2.00000%	$ 150,000

In 2006, the Company entered into participation agreements with several unrelated industry participants under which it would receive a 20% back-in interest after payout to the participants and the CEO would receive a 5% back-in interest. The agreements were renegotiated in 2010 reducing the total back-in interest by 40% with the Company receiving 12.5% and the CEO receiving 2.5%. The project, named La Posada, achieved multiple discrete payouts during 2013 based on differing participant cost basis and the participants assigned the agreed working interests directly to each of the Company and the CEO at time of payout.

NOTE G – FAIR VALUE MEASUREMENTS

Certain financial instruments are reported at fair value on the Consolidated Balance Sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels (see the Fair Value section of Note B – Summary of Significant Accounting Policies). The Company uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Fair Value of Financial Instruments (other than Commodity Derivative, see below) –The carrying values of financial instruments, excluding commodity derivatives, comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments.

Derivatives – The fair values of the Company's commodity derivatives are considered Level 2 as their fair values are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by the Company's counterparties for reasonableness. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which results in the Company using market prices and implied volatility factors related to changes in the forward curves. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. Because the Company's commodity derivative counterparty was Société Générale ("SocGen") at December 31, 2014 (see Note H – Commodity Derivative Instruments), the Company has not considered non-performance risk in the valuation of its derivatives.

	Fair value measurements at December 31, 2014			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$ -	$ 2,858,387	$ -	$ 2,858,387
Commodity derivatives – gas	-	1,883,259	-	1,883,259
Total assets	$ -	$ 4,741,646	$ -	$ 4,741,646
Liabilities:				
Commodity derivatives	$ -	$ -	$ -	$ -
Preferred stock derivative	-	-	-	-
Total liabilities	$ -	$ -	$ -	$ -

	Fair value measurements at December 31, 2013			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$ -	$ 818,637	$ -	$ 818,637
Total assets	$ -	$ 818,637	$ -	$ 818,637
Liabilities:				
Commodity derivatives – gas	$ -	$ 472,564	$ -	$ 472,564
Commodity derivatives – oil	-	423,217	-	423,217
Preferred stock derivative	-	-	51,290,414	51,290,414
Total liabilities	$ -	$ 895,781	$ 51,290,414	$ 52,186,195

Derivative instruments listed above include collars, swaps, and 3-way collars. For additional information on the Company's derivative instruments and derivative liabilities, see Note H – Commodity Derivative Instruments, and Note I – Preferred Stock.

At June 30, 2014 and as of the end of each of the prior quarters, level 3 inputs were used as inputs to a Monte Carlo option pricing model to calculate the value of Series A and Series B Preferred Stock and common stock. The June 30, 2014 calculation resulted in a value per share on a fully diluted and as-converted basis of $3,061. The actual simulation considered an approximate log-normal distribution for the market capital of the Company, and was estimated to evolve monthly over time (two steps per month) through February 28, 2015. At June 30, 2014, it was assumed that, in the event of a failed merger or other events, there was some modest probability that at the end of 2014 or early in 2015, the Company would either complete a Liquidity Event (as described in Note J – Stock-Based Compensation) or be sold. Each simulation considered and accounted for the probability of the completion of a Liquidity Event with some probability in each half-month time period in 2014. The volatility was assumed to be 39.45% and was derived from implied volatilities of a number of public companies (tickers: AXAS, CRK, CRZO, GDP, PQ, SFY, SGY and WRES) adjusted for the Company's relatively lower amount of financial leverage at June 30, 2014.

On September 10, 2014, the value of the preferred stock and associated derivative was marked to market. The preferred stock was converted to common stock as further described in Note M – Merger with Pyramid Oil Company and Goodwill. With the conversion of the shares of preferred stock to common stock, the value of the associated derivative liability was marked to market, then transferred to common stock equity.

A summary of the value and the changes in the Company's assets and liabilities classified as Level 3 measurements during 2014 and 2013 is presented below:

	Preferred Stock Derivative Liability
December 31, 2014	$ -
December 31, 2013	51,290,414
Total change	$ (51,290,414)

Debt – The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheets. For further discussion of the Company's debt, see Note L – Debt and Change in Banking Line and Agent Bank. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

Asset Retirement Obligations (ARO's) – The Company estimates the fair value of ARO's based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, amounts and timing of settlements, the credit-adjusted risk-free rate to be used and inflation rates. See Note D – Asset Retirement Obligations for a summary of changes in ARO's.

NOTE H – COMMODITY DERIVATIVE INSTRUMENTS

Objective and Strategies for Using Commodity Derivative Instruments – In order to mitigate the effect of commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of the Company's crude oil and natural gas, the Company enters into crude oil and natural gas price commodity derivative instruments with respect to a portion of the Company's expected production. The commodity derivative instruments used include variable to fixed price commodity swaps, two-way and three-way collars.

The fixed price swap and two-way collar contracts entitle the Company to receive settlement from the counterparty for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. The Company would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or selling price, which would be the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price with respect to each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price with respect to each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by the Company with a strike price below the floor price of the two-way collar. The Company receives price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, the Company receives the cash market price plus the difference between the two put option strike prices. This type of instrument allows the Company to capture more value in a rising commodity price environment, but limits the benefits in a downward commodity price environment.

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company elected to discontinue hedge accounting for all commodity derivative instruments beginning with the 2013 financial year. The balance in other comprehensive income ("OCI") at year-end 2012 will remain in AOCI until such time that the original hedged forecasted transaction occurs. The last of these contracts will expire in December 2016. Starting with year 2013, mark-to-market adjustments to the contracts that were in AOCI at year-end 2012 will not be made to AOCI, but instead are recognized in earnings, as are all other commodity derivative contracts going forward. As a result of discontinuing the application of hedge accounting, the Company's earnings are potentially more volatile. See Note G – Fair Value Measurements for a discussion of methods and assumptions used to estimate the fair values of the Company's commodity derivative instruments.

Counterparty Credit Risk – Commodity derivative instruments expose the Company to counterparty credit risk. The Company's commodity derivative instruments are with SocGen which is rated "A" by Standard and Poor's, "A2" by Moody's, and "A" by Fitch. Commodity derivative contracts are executed under master agreements which allow the Company, in the event of default, to elect early termination of all contracts. If the Company chooses to elect early termination, all asset and liability positions would be netted and settled at the time of election.

In conjunction with certain derivative hedging activity, the Company deferred the payment of $153,389 put premiums recorded in both current other deferred charges and current other accrued liabilities and is for production months January 2015 through December 2015. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company will begin amortizing the deferred put premium liabilities in January 2015.

Commodity derivative instruments open as of December 31, 2014 are provided below. Natural gas prices are New York Mercantile Exchange ("NYMEX") Henry Hub prices, and crude oil prices are NYMEX West Texas Intermediate, except for the oil swaps noted below that are based on Argus Light Louisiana Sweet.

	2015 Settlement	2016 Settlement
NATURAL GAS (MMBtu):		
3-way collars		
Volume	2,377,371	1,122,533
Ceiling sold price (call) *	$ 4.47	$ 4.35
Floor purchased price (put) *	$ 4.00	$ 4.10
Floor sold price (short put) *	$ 3.25	$ 3.25
Swaps		
Volume	458,622	-
Price *	$ 4.08	-
Reverse Swaps		
Volume	293,234	-
Price *	$ 4.33	-
CRUDE OIL (Bbls):		
3-way collars		
Volume	89,512	70,263
Ceiling sold price (call) *	$ 104.36	$ 106.39
Floor purchased price (put) *	$ 86.49	$ 92.38
Floor sold price (short put) *	$ 65.82	$ 72.38
Put Spread		
Volume	27,588	-
Floor purchased price (put) *	$ 90.00**	-
Floor sold price (short put) *	$ 75.00**	-

* Prices are weighted averages

** Contracts include a premium to be paid by the Company of $5.56 per barrel as the contracts mature ($153,389 total premium). The premium is not included in these prices.

Derivatives for each commodity are netted on the Consolidated Balance Sheets as they are all contracts with the same counterparty. The following table presents the fair value and balance sheet location of each classification of commodity derivative contracts on a gross basis without regard to same-counterparty netting:

	Fair value as of December 31,	
	2014	2013
Asset commodity derivatives:		
Current assets	$ 6,413,935	$ 1,109,403
Noncurrent assets	3,163,891	2,861,225
	9,577,826	3,970,628
Liability commodity derivatives:		
Current liabilities	(3,075,398)	(1,786,535)
Noncurrent liabilities	(1,760,782)	(2,261,237)
	(4,836,180)	(4,047,772)
Total commodity derivative instruments	$ 4,741,646	$ (77,144)

Sales of natural gas and crude oil on the Consolidated Statements of Operations are comprised of the following:

	Years Ended December 31,		
	2014	2013	2012
Sales of natural gas and crude oil	$ 38,659,392	$ 28,235,413	$ 19,684,132
Gains (losses) realized on settled contracts forcommodity derivatives	(1,420,217)	(524)	228,557
Gains (losses) on ineffectiveness ofcash flow hedges	-	-	712,681
Gains (losses) on market value ofopen contracts for commodity derivatives	4,724,985	(231,886)	544,237
Amortized gains from benefit of sold qualified gas options	93,750	72,600	128,512
Amortized losses from cost of purchased non-qualified oil calls	-	-	(16,004)
Total sales of natural gas and crude oil	$ 42,057,910	$ 28,075,603	$ 21,282,115

A reconciliation of the components of accumulated other comprehensive income (loss) in the Consolidated Statements of Changes in Equity is presented below:

	Years Ended December 31,					
	2014		2013		2012	
	Before tax	After tax	Before tax	After tax	Before tax	After tax
Balance, beginning of period	$ 63,041	$ 38,770	$ 437,140	$ 268,841	$ (111,628)	$ (68,651)
Net change in fair value	-	-	-	-	1,075,885	661,668
Gains reclassified to income	-	-	-	-	(398,604)	(245,141)
Amortized gains from benefit of sold qualified options realized in income	(93,755)	(57,659)	(72,600)	(44,649)	(128,513)	(79,035)
Other reclassifications due to expired contracts previously subject to hedge accounting rules	93,805	57,690	(301,499)	(185,422)	-	-
Balance, end of period	$ 63,091	$ 38,801	$ 63,041	$ 38,770	$ 437,140	$ 268,841

NOTE I – PREFERRED STOCK

9.25% Series A Cumulative Redeemable Preferred Stock -On October 23, 2014, the Company held an initial closing of its public offering of 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share, with a liquidation preference of $25.00 per share (the "Series A Preferred Stock"). The Company issued 477,273 shares at a public offering price of $22.00 per share, for gross proceeds of $10,500,006. On October 24, 2014, the Company held an additional closing for 30,466 shares of Series A Preferred Stock at a public offering price of $22.00 per share for gross proceeds of $670,252. In total, the Company received $10,430,894 net of the underwriters' discount and expenses. In addition to fees at the time of closing, the Company incurred estimated costs of $351,034 for the preferred stock issuance. The shares of Series A Preferred Stock trade on the NYSE MKT under the symbol "YUMAprA". The Series A Preferred Stock cannot be converted into common stock (except upon a change in control and in the event the Company chooses to not redeem the Series A Preferred Stock), but may be redeemed by the Company, at the Company's option, on or after October 23, 2017 (or in certain circumstances, prior to such date as a result of a change in control of the Company), at a redemption price of $25.00 per share plus any accrued and unpaid dividends. The Series A Preferred Stock has no stated maturity, is not subject to any sinking fund or mandatory redemption, and will remain outstanding indefinitely unless repurchased, redeemed or converted into common stock in connection with a change in control. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the Board of Directors, cumulative dividends at the rate of 9.25% per annum (the dividend rate) based on the liquidation price of $25.00 per share of the Series A Preferred Stock, payable monthly in arrears on each dividend payment date, with the first payment date of December 1, 2014. The Series A Preferred Stock is presented in the permanent equity section of the financial statements.

Series A and Series B Preferred Stock of Yuma Co. –Prior to the closing of the merger on September 10, 2014, Yuma Co. had two classes of preferred stock outstanding, the Series A and Series B. Immediately prior to the closing of the merger, these shares of preferred stock were converted to common stock of Yuma Co. At the closing of the merger, the common stock of Yuma Co. was converted into common stock of the Company.

During July 2011, Yuma Co. issued 14,605 shares of Series A Preferred Stock in connection with a private placement, realizing gross proceeds of $14,605,000 offset by offering expenses of $1,271,396 resulting in net proceeds of $13,333,604. The stated value and issue price of the Series A Preferred Stock was $1,000.00 per share and each share was convertible into one share of Yuma Co.'s common stock. The Series A Preferred Stock paid a cumulative dividend on a semi-annual basis of $30.00 per share out of funds legally available (subject to appropriate adjustment in the event of any stock dividend, stock split, combination or other similar recapitalization with respect to the Series A Preferred Stock and subject to increase as further described below) as declared by the board of directors of Yuma Co.. These dividends were cumulative from the date of issuance, whether or not such dividends were declared, and were payable semi-annually, when and as declared by the board of directors of Yuma Co., on June 30 and December 31 in each year. At the election of the board of directors of Yuma Co., the dividends on the Series A Preferred Stock could be paid in additional shares of Series A Preferred Stock. Since the Required Event, as defined below, had not occurred by September 30, 2013, the semi-annual dividend rate on the Series A Preferred Stock increased, commencing on October 1, 2013, to a semi-annual rate of $60.00. Further, since the Required Event had not occurred by December 31, 2012, March 31, 2013 or June 30, 2013, then on each date the Series A Conversion Price then in effect decreased by an amount such that the Series A Preferred Stockholders increased their aggregate ownership in the Company by one percent. The "Required Event", or "Liquidity Event", referred to the conversion of the Series A Preferred Stock to common stock and registration of these shares under the Securities Act of 1933, as amended (the "Securities Act"), and the listing on a national securities exchange, quoted on the OTC Bulletin Board or quoted on the Pink Sheets. At December 31, 2012, Yuma Co. had not met the requirements of the Required Event and, as a result, the conversion rate to common stock for shares of Series A Preferred Stock changed from one to one to a conversion rate of one share of Series A Preferred Stock to 1.067579 shares of common stock, effectively providing a one percent increase in equity ownership in Yuma Co. to the Series A Preferred Stock stockholders. During 2013, Yuma Co. did not meet the requirements of the Required Event and, as a result of the required adjustments in the conversion rate at March 31, 2013 and June 30 2013, the conversion rate of one share of Series A Preferred Stock increased to 1.207101257 shares of common stock.

During July and August 2012, Yuma Co. issued 18,590 shares of Series B Preferred Stock in a private placement, realizing gross proceeds of $18,590,000 offset by offering expenses of $1,406,295, resulting in net proceeds of $17,183,705. The stated value and issue price of the Series B Preferred Stock was $1,000.00 per share, and each share was convertible into 0.508185 shares of common stock. The Series B Preferred Stock paid a cumulative dividend on a semi-annual basis of $30.00 per share out of funds legally available (subject to appropriate adjustment in the event of any stock dividend, stock split, combination or other similar recapitalization). Such dividend was cumulative from the date of issuance of the Series B Preferred Stock, whether or not such dividends were declared, and were payable semi-annually, when and as declared by the board of directors of Yuma Co., on June 30 and December 31 in each year. At the election of the board of directors of Yuma Co., the dividends on the Series B Preferred Stock could be paid in additional shares of Series B Preferred Stock.

The Series A and Series B Preferred Stock is presented on the Company's balance sheet between Other Noncurrent Liabilities and Equity (the mezzanine section) since it has characteristics of both debt and equity. The carrying amount on the Company's balance sheets represents the net proceeds increased by accretion of stock issue costs less the value at time of origination of the embedded conversion feature. The accretion of issue costs increased the Preferred Stock by amortizing the costs to equity through the trigger date for the Company's repurchase of such shares.

Yuma Co. issued Series A and Series B Preferred Stock with certain embedded anti-dilution provisions (embodied weighted average ratchet or reset provisions) which provided for conversion price adjustments ("down-round protection") had additional shares of common or preferred stock been issued by Yuma Co. at a lower valuation than the valuation used at the time the Series A or Series B Preferred Stock was issued. In addition, the Series A and Series B Preferred Stock provided that Yuma Co. was obligated to repurchase these shares should the Required Event not occur by the trigger date of June 20, 2016 in the case of the Series A Preferred Stock and June 30, 2017 in the case of the Series B Preferred Stock. The down-round provision and the ability to "put" the stock back to Yuma Co. had the features of an option or derivative. The provisions of ASC 815, Derivatives and Hedging, required Yuma Co. to bifurcate the embedded derivative from the carrying value of the Series A and Series B Preferred Stock and record it on Yuma Co.'s balance sheet as a derivative liability, at fair value. Accordingly, at each reporting date, Yuma Co. marked the derivative liability to estimated fair value, with the resulting changes recognized in earnings. Since Yuma Co. was not public at the time, management elected to determine the fair value of this derivative using a Monte Carlo option pricing model with Level 3 inputs (see the Fair Value section of Note B – Summary of Significant Accounting Policies for Level 3 Valuation Techniques). The assumptions used were reviewed on a quarterly basis and were subject to change based primarily on management's assessment of the probability of various events. After the initial valuation, changes in fair value were made with the increase or decrease flowing to the Consolidated Statements of Operations as "Change in fair value of preferred stock derivative liability". Upon issuance of the Series A Preferred Stock in July 2011, the fair value of the associated derivative was $89.86 per share of Series A Preferred Stock, or an aggregate of $1,312,405. The December 31, 2013 fair value of the Series A derivative was $2,581.00 per share of Series A Preferred Stock, or an aggregate of $40,361,678. Upon issuance of the Series B Preferred Stock in July and August 2012, the fair value of the associated derivative was $55.00 for July and $52.79 for August per share of Series B Preferred Stock, or an aggregate of $1,016,715. The December 31, 2013 fair value of the Series B derivative was $556.00 per share of Series B Preferred Stock, or an aggregate of $10,928,736.

On June 30, 2013, December 31, 2013, and June 30, 2014, Yuma Co. elected to pay the semi-annual dividends to the preferred stockholders in additional shares of preferred stock (in kind), with cash payments being made in lieu of any fractional shares. The following shares and cash payments were issued to the existing preferred stockholders as of the record dates:

	June 30, 2013		December 31, 2013		June 30, 2014	
	Additional preferred shares	Cash payments	Additional preferred shares	Cash payments	Additional preferred shares	Cash payments
Series A Preferred Stock	403	$ 35,150	630	$ 45,360	893	$ 45,280
Series B Preferred Stock	533	$ 24,700	533	$ 40,690	536	$ 53,680

On September 15, 2014, the Company made the final cash dividend payment to the holders of record of the Series A and Series B Preferred Stock. The amount of the preferred stock dividends paid was as follows:

Series A Preferred Stock Dividends	$ 214,903
Series B Preferred Stock Dividends	131,289
Total Dividends	$ 346,192

The payment in kind to preferred stockholders was recorded at fair value using the valuation of the common stock performed by an outside consulting firm as further described in Note G – Fair Value Measurements, at the preferred conversion rate to common stock as of June 30, 2013 and December 31, 2013. Components of the total fair value of $4,133,380 for fiscal year 2014 and $5,412,281 for fiscal year 2013 for the preferred stock dividends consist of:

	December 31, 2014		December 31, 2013	
	Additional preferred shares	Dividends in kind	Additional preferred shares	Dividends in kind
Series A Preferred Stock	893	$ 3,299,603	1,033	$ 3,779,521
Series B Preferred Stock	536	$ 833,777	1,066	$ 1,632,760

Yuma Co. issued the above additional preferred shares to each class of preferred stock. The outstanding shares at December 31, 2014 and 2013 are as follows:

	Original shares	2013 stock dividends	Shares outstanding December 31, 2013	2014 stock dividends	Shares converted to common stock in 2014	Shares outstanding December 31, 2014
Series A Preferred Stock	14,605	1,033	15,638	893	(16,531)	-
Series B Preferred Stock	18,590	1,066	19,656	536	(20,192)	-

At the closing of the merger, the shares of Series A and Series B preferred stock were converted to common stock as reflected in the table below.

	Number of preferred shares	Conversion ratio to Yuma Co. common stock	Conversion ratio to Company common stock	Number of shares
Series A Preferred Stock	16,531	1.207101257	757.3374389993	15,112,295
Series B Preferred Stock	20,192	.508185000	757.3374389993	7,771,192

NOTE J – STOCK-BASED COMPENSATION

The Yuma Co. 2011 Stock Option Plan (the "Yuma Co. Plan") was adopted on June 21, 2011. On September 10, 2014, the shareholders of Pyramid adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"). Under these plans, the Board of Directors is authorized to grant stock options, stock awards (including restricted stock and restricted stock unit awards) and performance awards to officers, directors, employees and consultants.

Restricted Stock – The Company granted restricted stock awards ("RSAs") under the Yuma Co. Plan in 2013. These restricted stock awards granted to officers, directors and employees generally vest in one-third increments over a three-year period, and are contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

A summary of the status of the RSAs and changes for the year to date ended December 31, 2014 is presented below.

	Number of unvested RSA shares	Weighted average grant-date fair value
Unvested shares as of January 1, 2014	1,895,620	$3.22 per share
Granted on March 6, 2014	196,151	$3.89 per share
Granted on April 1, 2014	33,322	$3.89 per share
Granted on May 20, 2014	341,559	$3.96 per share
Vested	(107,291)	$2.98 per share
Forfeited	(406,690)	$3.42 per share
Unvested shares as of December 31, 2014	1,952,671	$3.40 per share

Stock Options – Pyramid issued stock options as compensation to non-employee directors under the Pyramid Oil Company 2006 Equity Incentive Plan (the "Pyramid Plan"). The options vested immediately, are exercisable for a five-year period from the date of the grant.

The following is a summary of the Company's stock option activity.

	Options	Weighted-average exercise price	Weighted-average remaining contractual life (years)	Aggregate intrinsic value
Outstanding at December 31, 2013	105,000	$ 5.17	4.66	$ -
Granted	-	-	-	-
Exercised	-	-	-	-
Forfeited	-	-	-	-
Outstanding at December 31, 2014	105,000	$ 5.17	3.66	$ -
Vested and expected to vest at December 31, 2014	105,000	$ 5.17	3.66	$ -
Exercisable at December 31, 2014	105,000	$ 5.17	3.66	$ -

As of December 31, 2014, there were no unvested stock options or unrecognized stock option expenses.

The following table summarizes the information about stock options outstanding and exercisable at December 31, 2014.

	Options Outstanding			Options Exercisable	
Exercise price	Number of shares	Weighted-average remaining life (years)	Weighted average exercise price	Number of shares	Weighted average exercise price
$ 5.40	5,000	1.42	$ 5.40	5,000	$ 5.40
$ 5.16	100,000	3.78	$ 5.16	100,000	$ 5.16
	105,000			105,000	

Restricted Stock Units – On April 1, 2013, the Company granted 163 Restricted Stock Units (for Yuma Co. shares) or "RSUs" to employees. Based on the exchange ratio of the merger, the RSUs converted into 123,446 RSUs. Each RSU represents a contingent right to receive one share of the Company's common stock upon vesting. In order to vest, an employee must have continuous service with the Company from time of the grant through April 1, 2016, the vesting date. The RSUs may be settled in cash and do not require the eventual issuance of common stock (although it is an election available to the Company, management intends to settle in cash); consequently, the awards are liability-based and the booked valuation will change as the market value for common stock changes. The Company utilized a Monte Carlo simulation option pricing model prepared by an outside consulting firm to value the RSUs from inception through June 30, 2014, and utilized a Black Scholes option pricing model prepared by an outside consulting firm at September 30, 2014. At December 31, 2014, the RSU's were valued at the common stock closing price of the Company on that date. Compensation expense is recognized over the three-year vesting period.

On December 25, 2014, the Company entered into a Separation Agreement and General Release of Claims ("Separation Agreement") with its former President and Chief Operating Officer which provided for, among other things, the forfeiture of 355,192 RSAs with various vesting dates and the issuance of an aggregate of 273,907 RSUs that vested December 31, 2014, with 254,973 to be issued on April 1, 2015 and 18,934 to be issued on May 20, 2015. The vesting of the units was subject to employee's continued employment with the Company through December 31, 2014 and compliance with the other provisions of the Separation Agreement.

A summary of the status of the unvested RSUs and changes during the year ended December 31, 2014 is presented below.

	Number of unvested RSUs	Weighted average grant-date fair value
Unvested RSUs as of January 1, 2014	119,659	$2.72 per share
Granted on December 25, 2014	273,907	$1.80 per share
Vested	(273,907)	$3.17 per share
Forfeited	(24,235)	$2.72 per share
Unvested RSUs as of December 31, 2014	95,424	$2.72 per share

NOTE K – EARNINGS PER COMMON SHARE

Earnings per common share are computed by dividing earnings available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Potential common stock equivalents are determined using the "if converted" method.

Potentially dilutive securities for the computation of diluted weighted average number of shares are as follows:

	Years Ended December 31, 2014		
	2014	2013	2012
Series A Preferred Stock	10,031,104	12,964,860	11,063,185
Series B Preferred Stock	5,263,585	7,259,079	3,067,217
Restricted Stock Awards	2,256,264	1,334,452	-
Restricted Stock Units	105,643	91,762	-
	17,656,596	21,650,153	14,130,402

The Series A and Series B Preferred Stock were converted to common stock on September 10, 2014, 253 days into the total 365 days for the twelve month period ended December 31, 2014. This shorter period accounts for the decrease in weighted average number of shares in the twelve months ended December 31, 2014 compared to the same period in 2013.

The Company excludes preferred stock and stock-based awards whose effect would be anti-dilutive from the calculation. For the years ended December 31, 2014, 2013 and 2012, adjusted earnings were losses, therefore common stock equivalents were excluded from the calculation of diluted net loss per share of common stock, as their effect was anti-dilutive.

NOTE L – DEBT AND CHANGE IN BANKING LINE AND AGENT BANK

	December 31,	
	2014	2013
Variable rate revolving credit facility payable to Société Générale, OneWest Bank, FSB, and View Point Bank, N.A., maturing May 20, 2017, secured by oil and natural gas properties held by Yuma Exploration and Production Company, Inc. and guaranteed by The Yuma Companies, Inc.	$ 22,900,000	$ 31,215,000
Installment loan due February 28, 2015, originating from the financing of insurance premiums at 3.65% interest rate.	282,843	178,027
	23,182,843	31,393,027
Less: current portion	(282,843)	(178,027)
Total long-term debt	$ 22,900,000	$ 31,215,000

On August 10, 2011, Exploration entered into a $125 million syndicated credit agreement with Amegy Bank National Association ("Amegy") as Administrative Agent, or Agent Bank. The maximum available under the revolving credit facility is determined by a formula based on the discounted value of the producing and non-producing crude oil and natural gas reserves (the borrowing base). Interest on the facility accrues at the Company's option based on prime as published by the Wall Street Journal, or a rate based on London Interbank Offering Rate ("LIBOR").

The prime and LIBOR base rates were increased by the following margins:

Borrowing base utilization	Prime margin	LIBOR margin
Utilization ≥ 75%	1.25%	3.50%
50% ≤ utilization < 75%	1.00%	3.25%
25% ≤ utilization < 50%	0.75%	3.00%
Utilization < 25%	0.50%	2.75%

On September 24, 2012, the credit agreement was amended whereby Union Bank N. A. (Union) joined the facility as a participant at 64.29% (Amegy was reduced to 35.71%) and replaced Amegy as Administrative Agent. Amegy, however, has remained the Company’s bank for regular operational banking functions. The amendment changed the interest rate margins as follows:

Borrowing base utilization	Prime margin	LIBOR margin
Utilization ≥ 90%	2.00%	3.00%
75% ≤ utilization < 90%	1.75%	2.75%
50% ≤ utilization < 75%	1.50%	2.50%
Utilization < 50%	1.25%	2.25%

On February 13, 2013, the credit agreement was further amended to add SocGen as a new participant and as a replacement for Union as the Administrative Agent, and to remove Amegy from the syndication (although still remaining the Company’s bank for treasury operations). The participation allocation became 68.75% for SocGen and 31.25% for Union. The new interest rate margins effective February 13, 2013 are as follows:

Borrowing base utilization	Prime margin	LIBOR margin
Utilization ≥ 90%	2.25%	3.25%
75% ≤ utilization < 90%	2.00%	3.00%
50% ≤ utilization < 75%	1.75%	2.75%
25% ≤ utilization < 50%	1.50%	2.50%
Utilization < 25%	1.25%	2.25%

On May 20, 2013, a third amendment to the credit agreement added OneWest Bank, FSB (“OneWest”) to replace Union with the new participation for SocGen and OneWest equal at 50/50. With the third amendment, the credit agreement maturity date was changed to May 20, 2017.

On September 27, 2013, the Borrowing Base Redetermination Agreement and Assignment added View Point Bank, N.A. (“View Point”) as a third lender in the credit agreement. Participating percentages at September 27, 2013 became 37.5% for SocGen, 37.5% for OneWest and 25% for View Point.

Effective April 22, 2014, Exploration entered into the fourth amendment to the credit agreement, which among other things, provided for a borrowing base of $40 million. A loan redetermination fee of $20,250 was paid but the expense is being amortized over the remaining loan life.

Costs paid to SocGen to bring it into the syndicate include a $150,000 arrangement fee, an $88,000 upfront fee, and $87,598 in attorneys' fees. Costs paid to replace Union with OneWest were a $50,000 arrangement fee, a $216,000 upfront fee and $37,061 in attorneys' fees. On September 27, 2013, the Company paid SocGen a $24,000 redetermination fee whereby the borrowing base was increased by $4.0 million to $40.0 million. Attorneys' fees for the redetermination were $4,080. All these costs are being amortized over the life of the loan. SocGen, as Agent Bank, is also paid an annual administrative fee of $25,000 amortized over the year. The unamortized Amegy and Union costs of $123,925 and $189,727 were written off immediately upon their exit from the syndicate. The Agent Bank also required all commodity hedges be moved from British Petroleum Corporation to SocGen and charged a fee of $175,000 for the novation. This fee was fully expensed.

The following summarizes interest expense for the years ended December 31, 2014, 2013 and 2012.

	Years Ended December 31,		
	2014	2013	2012
Credit facility	$ 1,109,153	$ 1,010,539	$ 714,826
Credit facility commitment fees	70,813	56,092	48,836
Amortization and write offs of credit facility loan costs	188,669	480,261	113,057
Insurance installment loan	13,640	16,161	10,587
Louisiana Mineral Board	-	32,383	-
Other interest charges	3,275	4,056	3,867
Capitalized interest	(1,059,350)	(1,031,816)	(681,090)
Total interest expense	$ 326,200	$ 567,676	$ 210,083

The terms of the credit agreement require Exploration to meet a specific current ratio, interest coverage ratio, and a funded debt to EBITDA ratio. The credit agreement also contains a covenant requiring ten percent availability under the current borrowing line in order to pay dividends on the Series A Preferred Stock. In addition, the credit agreement requires the guarantee of YCI. Exploration was in compliance with the loan covenants as of December 31, 2014.

Aggregate principal payments based on the Company's current borrowings as of December 31, 2014 for the next five years are shown below:

2015	$ 282,843
2016	-
2017	22,900,000
2018	-
2019	-

NOTE M – MERGER WITH PYRAMID OIL COMPANY AND GOODWILL

On September 10, 2014, a wholly owned subsidiary of Pyramid merged with and into Yuma Co. in exchange for 66,336,701 shares of common stock and Pyramid changed its name to "Yuma Energy, Inc." (the "merger"). As a result of the merger, the former Yuma Co. stockholders received approximately 93% of the then outstanding common stock of the Company and thus acquired voting control. Although the Company was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of Pyramid by Yuma Co. The transaction qualified as a tax-deferred reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code").

As a result of the merger announcement with Pyramid on February 6, 2014, expenses of approximately $1.3 million previously incurred by the Company in connection with exploring options to obtain a public listing were written off during the first quarter of 2014.

The merger was accounted for as a business combination in accordance with ASC 805 Business Combinations ("ASC 805"). ASC 805, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values.

A table of adjustments reflecting the allocation of the fair values and computation of goodwill is provided below. These adjustments reflect the elimination of the components of Pyramid's historical stockholders' equity, the estimated value of consideration paid by the Company in the merger using the closing price of its common stock on September 10, 2014 and the adjustments to the historical book values of Pyramid's assets and liabilities to their estimated fair values, in accordance with acquisition accounting. The Company believes the purchase price allocation is final as of the fourth quarter 2014 and that these estimates are reasonable and the significant effects of the merger are properly reflected.

	September 10, 2014 (as initially reported)	Measurement period adjustment (*i*)	September 10, 2014 (as adjusted)
Purchase Price(i):			
Shares of Pyramid common stock held by Pyramid shareholders	4,788,085	-	4,788,085
Pyramid common stock price (September 10, 2014 closing price)	$ 4.70	$ -	$ 4.70
Fair value of Pyramid common stock issued	$ 22,504,000	$ -	$ 22,504,000
Consideration paid to Pyramid's shareholders	-		-
Issuance of 100,000 shares to Pyramid affiliated persons at $5.01 per share (September 11, 2014 closing price)	501,000	-	501,000
Fair value of Pyramid options assumed by the Company*(ii)*	100,500	-	100,500
Total purchase price	23,105,500	-	23,105,500
Estimated Fair Value of Liabilities Assumed:			
Current liabilities	633,917	-	633,917
Noncurrent deferred tax liability*(iii)*	4,879,724	-	4,879,724
Other noncurrent liabilities (asset retirement obligation)	1,334,278	(390,327)	943,951
Amount attributable to liabilities assumed	6,847,919	(390,327)	6,457,592
Total purchase price plus liabilities assumed	29,953,419	(390,327)	29,563,092
Estimated Fair Value of Assets Acquired:			
Current assets	9,066,589	-	9,066,589
Oil and natural gas properties*(iv)*	10,726,715	-	10,726,715
Net other property and equipment	4,158,420	-	4,158,420
Other noncurrent assets	261,380	-	261,380
Amount attributable to assets acquired	24,213,104	-	24,213,104
Goodwill*(i)*	$ 5,740,315	$ (390,327)	$ 5,349,988

(i) Under the terms of the merger agreement, Pyramid shareholders own 7% of the Company. The total purchase price is based upon the closing price of $4.70 per share of Pyramid common stock on September 10, 2014 and 4,788,085 shares of Pyramid common stock outstanding at the effective time of the merger. The difference between the purchase price plus the liabilities of Pyramid assumed in the merger less the estimated fair value of the Pyramid assets acquired is shown as goodwill.

During the fourth quarter 2014 (within the allowed measurement period for adjustments to goodwill), the Pyramid asset retirement obligation as of the merger date was re-evaluated for cost projections, asset lives were adjusted to reflect the updated reserve report, inflation factors were updated and the credit adjusted risk-free rate is now based on the Company's outstanding debt cost. The result was a decrease of $390,327 to the liability and an equal decrease to goodwill.

(ii) To adjust for the outstanding stock options to purchase common stock that were assumed by the Company with the merger. The $100,500 fair value of the assumed options was calculated using the Black Scholes valuation model with assumptions for the following variables: common stock price, risk-free interest rates, and the Company's stock volatility.

(iii) The Company received a carryover tax basis in Pyramid's assets and liabilities because the merger was not a taxable transaction under the Code. Based upon the preliminary purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from Pyramid, net of the existing Pyramid deferred tax asset of $0.5 million, is expected to result in a combined deferred tax liability of approximately $16.2 million, an increase of approximately $5.4 million to the Company's and Pyramid's existing $10.8 million net deferred tax liability.

(iv) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was based on the NYMEX price forecasts as of August 29, 2014 for oil and September 2, 2014 for natural gas, adjusted for differentials calculated from the 2013 historic Pyramid oil and gas prices versus the NYMEX oil (WTI) and gas average monthly prices, after adjustment for transportation fees.

Due to the significant decline in oil commodity prices in the fourth quarter 2014, goodwill was considered for possible impairment at year end. The assumptions the Company used in calculating its reporting unit fair value (the Company has a single reporting unit) included its market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Both year-end estimates of fair value exceeded book value. However, material adverse changes to any of these factors could lead to an impairment of all or a portion of the Company's goodwill in future periods.

The following unaudited pro forma combined results of operations are provided for the years ended December 31, 2014, 2013 and 2012 as though the merger had been completed as of the beginning of the earliest period presented, or January 1, 2012. These pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of Pyramid. Pyramid's historical property impairment expenses recognized under the successful efforts method of accounting were eliminated as they would not have been incurred under full cost accounting. Pyramid's historical depletion of oil and gas property was also adjusted to reflect the change to full cost accounting. These supplemental pro forma results of operations are provided for illustrative purposes only, and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the merger or any estimated costs that will be incurred to integrate Pyramid. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Years Ended December 31,		
	2014	2013	2012
		(Unaudited)	
Revenues	$ 46,238,208	$ 33,534,396	$ 26,879,236
Net income (loss)	$ (3,388,094)	$ (7,834,907)	$ 2,426,418
Net income (loss) per share:			
Basic	$ (.07)	$ (.19)	$ .06
Diluted	$ (.07)	$ (.19)	$ .04

For the year ended December 31, 2014, the Company recognized $945,580 of sales of natural gas and crude oil less lease operating expenses, production taxes and other operating expenses of $1,285,200 related to properties acquired in the merger. Additionally, non-recurring transaction costs of $2,226,719 and $124,222 related to the merger for the fiscal years 2014 and 2013, respectively, and costs of $1,287,285 to explore other options for a public listing expensed in 2014 are included in the Consolidated Statements of Operations as general and administrative expenses; however, these non-recurring transaction costs have been excluded from the pro forma results in the above table.

NOTE N – STOCKHOLDERS' EQUITY

1. **Common Stock**

The Company is authorized to issue up to 300,000,000 shares of common stock, no par value per share. The holders of common stock are entitled to one vote for each share of common stock, except as otherwise required by law. From the date of issuance of the Series A Preferred Stock (July 2011) and the Series B Preferred Stock (July and August 2012), until their conversion into common stock at the closing of the merger, no dividends could be declared or paid or set apart for payment and no other distribution could be declared or made or set apart for payment, in each case except for certain property distributions as defined in the Certificate of Incorporation of Yuma Co., and detailed in Note F – Related Party Transactions. In addition, during this period, holders of common stock could not vote on any amendment to the Certificate of Incorporation of Yuma Co. that related solely to the terms of the preferred stock.

2. **Yuma Co. 2011 Stock Option Plan**

Effective June 21, 2011, Yuma Co. adopted the 2011 Stock Option Plan ("Yuma Co. Plan"). The Yuma Co. Plan provided, among other things, for the granting of up to 6,000 (or approximately 4,544,025 shares based on the merger exchange ratio) shares of common stock as awards to key employees, officers, directors, and consultants of the Company by the Board of Directors. An award could take the form of stock options, stock appreciation rights ("SARs"), restricted stock awards ("RSAs") or restricted stock units ("RSUs"). At its meeting on August 1, 2014, the Board of Directors of Pyramid approved the assumption and amendment and restatement of the Yuma Co. Plan, which assumption was effective as of September 10, 2014 ("Plan Effective Date"). Following the Plan Effective Date, there were approximately 2,472,200 shares of common stock that were subject to outstanding restricted stock awards and restricted stock unit awards granted by Yuma Co. under the Yuma Co. Plan and that were assumed by the Company. Further, on September 11, 2014, the Board determined that no additional awards would be granted under the Yuma Co. Plan, and that the 2014 Plan would be used going forward.

3. **2014 Long-Term Incentive Plan**

On August 1, 2014, the board of directors of Pyramid adopted the 2014 Long-Term Incentive Plan (the "2014 Plan"), subject to shareholder approval at the 2014 Special Meeting of Shareholders. The shareholders of Pyramid approved this proposal at the Special Meeting held September 10, 2014 and became effective as of that date.

Under the 2014 Plan, YEI may grant stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance units, performance bonuses, stock awards and other incentive awards to YEI employees or those of YEI's subsidiaries or affiliates. YEI may also grant nonqualified stock options, restricted stock awards, restricted stock units, stock appreciations rights, performance units, stock awards and other incentive awards to any persons rendering consulting or advisory services and non-employee directors, subject to the conditions set forth in the 2014 Plan. Generally, all classes of YEI's employees are eligible to participate in the 2014 Plan.

The 2014 Plan provides that a maximum of 8,900,000 shares of common stock may be issued in conjunction with awards granted under the 2014 Plan. Awards that are forfeited under the 2014 Plan will again be eligible for issuance as though the forfeited awards had never been issued. Similarly, awards settled in cash will not be counted against the shares authorized for issuance upon exercise of awards under the 2014 Plan.

The 2014 Plan provides that a maximum of 1,000,000 shares of common stock may be issued in conjunction with incentive stock options granted under the 2014 Plan. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with stock options and/or stock appreciation rights to any eligible employee in any calendar year to 1,500,000 shares. The 2014 Plan also limits the aggregate number of shares of common stock that may be issued in conjunction with the grant of restricted stock awards, restricted stock unit awards, performance unit awards, stock awards and other incentive awards to any eligible employee in any calendar year to 700,000 shares.

NOTE O – INCOME TAXES

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently due plus deferred taxes related primarily to differences between the basis of property and equipment for financial reporting versus income tax reporting. The deferred taxes represent the future tax return consequences of those differences that will either be taxable or deductible when the differences in the basis of assets and liabilities reverse.

The Company recognizes and measures income tax benefits that are more likely than not to be sustained on eventual examination or settlement. Deferred tax assets are recorded to the extent the Company believes these assets will more likely than not be realized.

The Company does not have any unrecognized tax benefits for the years ended December 31, 2014 and 2013. In addition, the Company does not anticipate any unrecognized tax benefits during the next twelve months from the date these financials were available to be issued, March 30, 2015.

The Company did not incur any income tax deficiencies during fiscal years 2012, 2013, and 2014, and therefore had no interest or penalties assessed during the years ended December 31, 2012, 2013, and 2014.

The tax years of the Company that remain subject to examination by the Internal Revenue Service and other tax authorities are fiscal years 2011, 2012, 2013, and 2014.

The Company follows the liability and asset approach in accounting for income and state franchise taxes as required by the provisions of FASB concerning accounting for income taxes. Deferred tax liabilities and assets are determined using the tax rates for the period in which those accounts are expected to be paid or received.

Provisions for income taxes are composed of the following for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
Current income taxes:			
Federal	$ -	$ -	$ -
State	-	-	-
Total	-	-	-
Deferred income taxes (benefit):			
Federal	(2,377,192)	2,705,688	2,744,068
State	(176,662)	374,584	354,241
Total	(2,553,854)	3,080,272	3,098,309
Total taxes (benefit) on income	$ (2,553,854)	$ 3,080,272	$ 3,098,309

Deferred tax liabilities (assets) that are recognized for the estimated future tax effects attributable to temporary differences and carryforwards at year-end are as follows:

	Years Ended December 31, 2014	Years Ended December 31, 2013
Current:		
Deferred tax asset (stock-based compensation)	$ (1,196,378)	$ (146,964)
Deferred tax asset (other asset)	(396,668)	-
Deferred tax liability (hedges)	1,819,119	-
Total current deferred tax asset and liability	$ 226,073	$ (146,964)
Noncurrent:		
Deferred tax liability (hedges)	$ 24,290	$ 24,262
Deferred tax liability from excess of book basis over tax basis of certain assets including property, plant and equipment	30,081,222	23,116,582
	30,105,512	23,140,844
Stock-based compensation	(9,344)	(27,079)
Alternative minimum tax credit carryforwards	(121,686)	(121,686)
Net operating loss ("NOL") carryforwards	(15,585,820)	(9,831,874)
Deferred tax asset	(15,716,850)	(9,980,639)
Net deferred tax liability	$ 14,388,662	$ 13,160,205

The deferred tax assets at December 31, 2014 and 2013 of $15,837,149 and $9,980,639, respectively, consist of deductible temporary differences related to operating loss carryforwards, unrealized losses from oil and natural gas hedges, and tax credit carryforwards and stock-based compensation generated by the consolidated group:

Year NOL generated	NOL remaining	Year of expiration
2014	$ 11,759,312	2034
2013	9,417,693	2033
2012	8,082,421	2032
2011	5,511,938	2031
2009	4,844,318	2029
2007	1,095,474	2027
2002	3,050,662	2022
Total	$ 43,761,818	

The tax provisions differ from the amounts that would be calculated by using federal statutory rates of 35 percent to calculate income taxes because (i) no tax benefit has been recognized for nondeductible expenses; (ii) the Companies are subject to various state income taxes; and (iii) the tax provisions consider the effect of graduated rates, as follows:

	Years Ended December 31, 2014	2013	2012
Amount computed using the statutory rate	$ (7,972,651)	$ (10,489,441)	$ (4,084,907)
Increase (reduction) in taxes resulting from:			
Non-deductible change in value of preferred stock derivative liability	5,486,895	9,190,496	5,984,476
State taxes	(210,021)	254,645	236,045
Other	141,923	4,124,572	962,695
Income tax expense (benefit)	$ (2,553,854)	$ 3,080,272	$ 3,098,309

For the year ended December 31, 2013, the Other, net amount relates primarily to changes in estimates to net operating losses, depletion and amortization.

When the Company believes that it is more likely than not that a net operating loss or credit carryforward may expire unused, it establishes a valuation allowance against the loss or credit. No valuation allowance has been established as of December 31, 2014 or 2013. Income taxes are allocated among the companies in the consolidated group on the basis of the tax effect each company contributed to income taxes for the years 2014 and 2013.

NOTE P – CONTINGENCIES

1. **Certain Legal Proceedings**

From time to time, the Company is party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes, if determined in a manner adverse to the Company, could have a potential material adverse effect on its financial condition, results of operations, or cash flows.

On July 9, 2014, Nabors Drilling USA, L.P. and other Nabors entities and Yuma Energy, Inc. and several of its wholly owned subsidiaries were named in a lawsuit filed in the District Court of Harris County, Texas, in the 80^{th} Judicial District, concerning the death of an employee of Timco Services during the drilling of the Crosby 12-1 well. The Company has tendered its defense to its liability insurance carriers who are responding. Management believes that the Company has adequate insurance to meet this potential claim.

2. **Environmental Remediation Contingencies**

As of September 30, 2014, there were no known environmental or other regulatory matters related to the Company's operations that were reasonably expected to result in a material liability to the Company. The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Exploration has been named as one of 97 defendants in a matter entitled *Board of Commissioners of the Southeast Louisiana Flood Protection Authority – East, Individually and As the Board Governing the Orleans Levee District, the Lake Borgne Basin Levee District, and the East Jefferson Levee District v. Tennessee Gas Pipeline Company, LLC, et al.,* Civil District Court for the Parish of Orleans, State of Louisiana, No. 13-6911, Division "J" - 5, now removed as Civil Action No. 13-5410, before the United Stated District Court, Eastern District of Louisiana. Plaintiff filed the suit on July 24, 2013 seeking damages and injunctive relief arising out of defendants' drilling, exploration, and production activities from the early 1900s to the present day in coastal areas east of the Mississippi River in Southeast Louisiana.

The suit alleges that defendants' activities have caused "removal, erosion, and submergence" of coastal lands resulting in significant reduction or loss of the protection such lands afforded against hurricanes and tropical storms. Plaintiff alleges that it now faces increased costs to maintain and operate the man-made hurricane protection system and may reach the point where that system no longer adequately protects populated areas.

Plaintiff lists hundreds of wells, pipelines, and dredging events as possible sources of the alleged land loss. Exploration is named in association with 11 wells, four rights-of-way, and one dredging permit. The suit does not specify any deficiency or harm caused by any individual activity or facility.

Although the suit references various federal statutes as sources of standards of care, plaintiff claims that all causes of action arise under state law: negligence, strict liability, natural servitude of drain, public nuisance, private nuisance, and as third-party beneficiary under breach of contract.

As of December 31, 2014, the Company had tendered its defense to its liability insurance carriers who are responding. At December 31, 2014, the Company could not predict the outcome of this case or, in management's opinion, assess any potential liability; therefore no liability has been recorded on the Company's books.

NOTE Q – EMPLOYEE BENEFIT PLANS

The Company has a defined contribution 401(k) plan (the "Plan") for its qualified employees. Employees may contribute any amount of their compensation to the Plan, subject to certain Internal Revenue Service annual limits and certain limitations for employees classified as high income. The Plan provides for discretionary matching contributions by the Company, and the Company currently provides a match for non-highly compensated employees only at a rate of 100 percent of each employee's contribution up to 4 percent of the employee's base salary. The Company contributed $38,827 and $33,412 under the Plan for the years ended December 31, 2014 and 2013, respectively.

The Company provides medical, dental, and life insurance coverage for both employees and dependents, along with long-term disability and accidental death and dismemberment coverage for employees only. The Company pays the full cost of coverage for all insurance benefits except medical. The Company's contribution toward medical coverage is 85 percent for the employee portion of the premium, and a variable percentage of the dependent portion, depending on employee compensation levels.

The Company offers paid vacations to employees in time increments determined by longevity and individual employment contracts. The Company policy provides a limited carry forward of vacation time not taken during the year. The Company recorded an accrued liability for compensated absences of $166,660 and $123,406 for the years ended December 31, 2014 and 2013, respectively.

The Company maintains employment contracts with members of its exploration staff and with certain key employees of the Company. As of December 31, 2014, future employment contract salary commitments were $3,160,373, excluding automatic renewals, evergreen and month-to-month provisions, and potential Annual Incentive Plan awards as described below.

The Company adopted the 2014 Plan as described in Note N – Stockholders' Equity. Note J – Stock-Based Compensation describes restricted stock awards granted under the 2014 Plan.

During December 2011, the Company adopted an employee Annual Incentive Plan ("AIP"). Under the AIP, the Board of Directors establishes certain performance metrics by which management is to be measured annually. These metrics are determined annually and awards of restricted stock, cash, or some combination of both may be made to members of the management team. The Board will meet during 2015 to evaluate the management team and determine any awards that may be due for 2014. To the extent compensation costs relate to employees directly involved in exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expense.

NOTE R – FINANCIAL INSTRUMENTS WITH OFF-BALANCE SHEET RISK, CONCENTRATIONS OF CREDIT RISK, AND CONCENTRATIONS IN GEOLOGIC PROVINCES

1. **Off-Balance Sheet Risk**

The Company does not consider itself to have any material financial instruments with off-balance sheet risks.

2. **Concentrations of Credit Risk**

The Company maintains cash deposits with banks that at times exceed applicable insurance limits. The Company reduces its exposure to credit risk by maintaining such deposits with high quality financial institutions. The Company has not experienced any losses in such accounts.

Substantially all of Exploration's accounts receivable result from oil and natural gas sales, joint interest billings and prospect sales to oil and natural gas industry partners. This concentration of customers, joint interest owners and oil and natural gas industry partners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic and other conditions. Such receivables are generally not collateralized; however, certain crude oil purchasers have been required to provide letters of guaranty from their parent companies.

3. **Concentrations in Geologic Provinces**

The Company has a significant portion of its crude oil production and associated infrastructure concentrated in state waters and coastal bays of Louisiana. These properties have exposure to named windstorms. The Company carries appropriate property coverage limits, but does not carry business interruption coverage for the potential lost production. The Company has changed its strategic direction to focus on onshore geological provinces which the Company believes have little or no hurricane exposure.

NOTE S – OTHER DISCLOSURES

1. **Other Income (Expense)**

	December 31, 2014	2013	2012
Bank-mandated derivative instruments novation cost	$ -	$ (175,000)	$ -
Louisiana sales tax settlement	-	(44,149)	-
Louisiana Mineral Board audit	-	(23,686)	-
Other	25,378	2,218	7,099
Total	$ 25,378	$ (240,617)	$ 7,099

2. **Other Receivables**

	December 31, 2014	2013
December 2014 settled oil derivative instruments	$ 407,003	$ -
Debit balances for trade payables	187,031	163,802
Refund from PPI for duplicate charges	89,544	89,544
D&O insurance premium adjustment	16,356	-
Blowout insurance premium adjustment	-	162,075
Other	(1,943)	2,429
Total	$ 697,991	$ 417,850

3. **Prepayments**

	December 31, 2014	2013
Insurance	$ 536,410	$ 209,415
Exploration and drilling costs	71,893	187,145
Property taxes	56,992	-
Software licenses	44,172	8,593
Taxes and fees	21,882	-
Software maintenance agreements	19,105	14,099
Geological well database subscription	19,055	-
Other subscriptions	6,355	13,560
Services	4,530	-
Other	1,840	1,179
Total	$ 782,234	$ 433,991

4. Other Current Deferred Charges

	December 31, 2014	December 31, 2013
Loan fees	$ 189,409	$ 162,416
Deferred premium on 2015 oil derivative instruments	153,389	-
Total	$ 342,798	$ 162,416

5. Other Noncurrent Assets

	December 31, 2014	December 31, 2013
Loan fees	$ 262,200	$ 384,953
Deferred offering costs	-	1,257,160
Total	$ 262,200	$ 1,642,113

6. Other Accrued Liabilities

	December 31, 2014	December 31, 2013
Salaries and bonuses	$ 479,537	$ 184,072
Ad valorem taxes	172,444	-
Vacation	166,660	123,406
Severance taxes	164,374	170,531
Commodity hedge settlement	153,389	21,463
Insurance	119,121	-
Sales and use tax	81,661	98,818
Accounting and audit	22,964	158,368
Interest expense	9,327	46,946
Pre-initial public offering expenses	-	259,223
Fees for commodity hedging advisor	-	62,631
Other	50,088	1,825
Total	$ 1,419,565	$ 1,127,283

NOTE T – SALES TO MAJOR CUSTOMERS

The Company generally sells crude oil and natural gas to numerous customers on a month-to-month basis. Four customers accounted for approximately 74 percent, 78 percent, and 79 percent of unaffiliated oil and natural gas sales in the years ended December 31, 2014, 2013 and 2012, respectively.

NOTE U – LEASES

The Company leases its primary office space of 15,180 square feet for $22,770 per month, plus $50 per month for each employee or contractor parking space. The lease term expires on December 31, 2017. On November 1, 2012, the monthly rent was reduced to $21,821 on a triple-net basis, and then escalated by 1.45 percent for the period November 1, 2013 through October 31, 2014. The lease then escalates by approximately 2.8 percent each year thereafter.

The Company currently leases approximately 3,200 square feet of office space at an off-site location as a storage facility. The current lease expires on April 30, 2017. The lease called for a security deposit of $2,684, and monthly rent of $1,949 commencing on May 1, 2014, escalating to $2,045 on May 1, 2015 and $2,141 on May 1, 2016.

Aggregate rental expense for fiscal years 2014, 2013 and 2012 was $531,127, $534,275 and $378,192, respectively. As of December 31, 2014, future minimum rentals under all noncancellable operating leases are as follows:

2015	$	567,480
2016		575,868
2017		561,106
2018		2,264
2019		-

NOTE V – AT MARKET SECURITY SALES

The Company entered into an At Market Sales Issuance Agreement (“Sales Agreement”) with an investment banking firm (the “Agent”) on December 19, 2014. Under the Sales Agreement, the Company may sell both common stock and Series A Preferred Stock pursuant to the Registration Statement on Form S-3 of the Company filed on November 5, 2013 (Registration No. 333-192094), which became effective under the Securities Act on November 21, 2013. Under the Sales Agreement, the Company may offer and sell up to $18,829,742 in the aggregate of common stock and Series A Preferred Stock from time to time through the Agent. Upon the Company’s delivery and the Agent’s acceptance of a placement notice, the Agent will use its commercially reasonable efforts, consistent with its sales and trading practices, to sell any shares subject to the placement notice. As of December 31, 2014, no shares had been issued under the Sales Agreement (see Note W – Subsequent Events).

NOTE W – SUBSEQUENT EVENTS

The Company has evaluated subsequent events through March 30, 2015, the date these financial statements were available to be issued. The Company is not aware of any subsequent events which would require recognition or disclosure in the financial statements, except as noted below or already recognized or disclosed.

1. Sixth Amendment to Credit Agreement

On January 23, 2015, Exploration, entered into the Sixth Amendment (the “Amendment”) to that certain credit agreement dated August 10, 2011 with SocGen as Administrative Agent and Issuing Bank, and each of the lenders and guarantors.

Pursuant to the Amendment, (i) the borrowing base under the credit agreement remained at $40.0 million until the next borrowing base redetermination date scheduled for February 1, 2015, subject to a loan covenant requiring a ten percent availability under the line in order to pay dividends on any preferred stock, (ii) the Company may issue additional series of preferred stock subject to certain restrictions, (iii) the definition of “Change of Control” has been amended and restated; (iv) the Company has pledged the stock of Exploration; (v) Exploration has pledged its interest in POL, and (vi) the properties held by the Company in the state of California were transferred from the Company to POL and were mortgaged under the credit agreement. In addition, Exploration’s properties in North Dakota were mortgaged. The borrowing base for the Company is currently being redetermined. The Company expects the new borrowing base to be set somewhat lower, but cannot estimate the ultimate amount at this time.

2. Orleans Levee Board

Exploration was named as one of 97 defendants in a lawsuit filed by the Levee Board of Orleans as described in Note P – Contingencies. On February 13, 2015, the federal judge adjudicating the matter granted defendants “Joint Motion to Dismiss for Failure to State a Claim Under Rule 12(b)(6)”, thereby dismissing plaintiff’s claims with prejudice in the matter. On February 20, 2015, the Board of Orleans filed a notice of appeal to the U. S. Fifth Circuit. The Company will continue to contest plaintiff’s legal arguments and factual assertions. At this point in the legal process, no evaluation of the likelihood of an unfavorable outcome or associated economic loss can be made.

3. Hedges

On February 18, 2015, the Company cleared all of its natural gas and crude oil options, realizing $4.03 million. The Company retained its existing natural gas swap positions. Concurrent with the clearing of the Company's option positions and during the following day, the Company entered into new swap transactions for crude oil and natural gas for the balance of 2015 and all of 2016. In addition, the Company entered into three-way collars for 2017 for both natural gas and crude oil.

4. Sales of Securities

The Company has entered into a Sales Agreement with an investment banking firm as described in Note V – At Market Security Sales. The Company initiated the sales of securities under the Sales Agreement on February 18, 2015, and as of March 25, 2015, the Company has sold the following securities for the net proceeds listed below.

	Shares	Net Proceeds
Common Stock	221,159	$ 328,008
Series A Preferred Stock	37,769	$ 746,345
Totals		$ 1,074,353

NOTE X – SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GASEXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

1. **Costs Incurred**

Costs incurred in oil and natural gas property acquisition, exploration and development activities, all of which are conducted within the continental United States, are summarized below:

	December 31,		
	2014	2013	2012
Property acquisition costs - unproved	$ 1,105,782	$ 3,865,932	$ 17,025,756
Property acquisition costs - proved	3,349,473	8,539,134	1,800,385
Sales proceeds - unproved	(359,667)	(679,266)	(1,386,649)
Sales proceeds - proved	(307,600)	(718,000)	-
Exploration costs	426,909	2,504,087	4,931,623
Development costs	20,139,409	11,910,179	7,699,903
Capitalized asset retirements costs	241,629	5,795,400	173,432
Total costs incurred	$ 24,595,935	$ 31,217,466	$ 30,244,450

The Company sells oil and natural gas prospects. The gains or losses from these sales are recorded as adjustments to the full cost pool under U.S. Securities and Exchange Commission ("SEC") guidelines. Prospect profits were $28,616, $50,346 and $234,105 for fiscal years 2014, 2013 and 2012, respectively.

2. Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization:

	December 31, 2014	December 31, 2013
Oil and gas properties, full cost method:		
Not subject to amortization:		
Prospect inventory	$ 14,913,126	$ 14,587,986
Property acquisition costs - unproved	8,623,344	8,202,369
Well development costs - unproved	2,170,582	1,249,718
Subject to amortization:		
Property acquisition costs - proved	50,744,401	36,999,813
Well development costs - proved	74,440,227	56,460,276
Capitalized costs - unsuccessful	52,539,407	50,849,905
Capitalized asset retirement costs	8,806,828	8,565,199
Total capitalized costs	212,237,915	176,915,266
Less accumulated depreciation, depletion and amortization	(103,929,493)	(84,438,840)
Net capitalized costs	$ 108,308,422	$ 92,476,426

3. Reserves

Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules, the price is calculated using the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period (if the first day of the month occurs on a weekend or holiday, the previous business day is used), unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. A project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geosciences and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Developed natural gas and oil reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

The information below on our natural gas and oil reserves is presented in accordance with regulations prescribed be the SEC, with guidelines established by the Society of Petroleum Engineers' Petroleum Resource Management System, as in effect as of the date of such estimates. The Company's reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. Such changes could be material and could occur in the near term.

The Company does not prepare engineering estimates of proved oil and natural gas reserve quantities for all wells. The Company only prepares engineering studies of estimated oil and natural gas quantities on a consolidated basis. The Company has a quantity of interests that, individually, are immaterial and are excluded from prepared engineering studies. Accounting sales volumes and receipts differ from amounts prepared by internal engineers and included in the following tables.

	2014	2013	2012
Barrels of oil and condensate:			
Proved developed and undeveloped reserves:			
Beginning of year	14,381,960	7,739,964	1,839,425
Revisions of previous estimates	(565,143)	(1,142,654)	(132,352)
Purchases of oil and gas properties	472,132	7,959,600	5,976,234
Extensions and discoveries	51,993	92,152	225,063
Sale of oil and gas properties	-	-	-
Production	(329,599)	(267,102)	(168,406)
End of year	14,011,343	14,381,960	7,739,964
Proved developed reserves - January 1,	2,099,701	1,474,015	1,236,002
Proved developed reserves - December 31,	2,347,482	2,099,701	1,474,015
Proved undeveloped reserves - January 1,	12,282,259	6,265,949	603,423
Proved undeveloped reserves - December 31,	11,663,861	12,282,259	6,265,949

	2014	2013	2012
Thousands of cubic feet of natural gas:			
Proved developed and undeveloped reserves:			
Beginning of year	38,372,369	31,071,137	17,020,496
Revisions of previous estimates	(479,438)	(8,281,139)	(463,712)
Purchases of oil and gas properties	81,177	16,495,803	12,931,203
Extensions and discoveries	-	362,806	2,163,825
Sale of oil and gas properties	-	-	-
Production	(2,714,586)	(1,276,238)	(580,675)
End of year	35,259,522	38,372,369	31,071,137
Proved developed reserves - January 1,	10,316,516	10,156,754	5,287,966
Proved developed reserves - December 31,	7,786,537	10,316,516	10,156,754
Proved undeveloped reserves - January 1,	28,055,853	20,914,383	11,732,530
Proved undeveloped reserves - December 31,	27,472,985	28,055,853	20,914,383

Revisions to previously estimated reserves for both natural gas and crude oil were primarily caused by (i) commodity price reductions in 2014 causing wells to reach their economic limits sooner thus producing fewer reserves and causing some proved undeveloped locations to become uneconomic; (ii) downward revisions to the Masters Creek Crosby 14-1 well after the well was drilled and completed.

4. Internal Controls Over Reserve and Future Net Revenue Estimation

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserve estimates and future net revenues, has over 14 years of experience in the oil and gas industry. His experience includes detailed evaluation of reserves and future net reserves for acquisitions, divestments, bank financing, long range planning, portfolio optimization, strategy and end of year financial reports. He has a B.S. in Petroleum Engineering from Texas A&M University, M.S. in Finance from University of Houston, and MBA from Rice University. He is a member of the Society of Petroleum Engineers (the "SPE"). The procedures and methods used by the principal engineer in preparing internal estimates of proved reserves and future net cash flows are approved by the SPE's Petroleum Resource Management System ("PMRS") with no risks applied.

At December 31, 2012, Pressler Petroleum Consultants ("Pressler") performed an independent engineering evaluation using the same guidelines established by PMRS to obtain an independent estimate of the proved reserves and future net revenues. During 2013, the Company changed outside engineering firms for the evaluation of its reserves. The Company hired Netherland, Sewell & Associates, Inc. ("NSAI") to evaluate its reserve portfolio, replacing Pressler Petroleum Consultants. At December 31, 2014 and 2013, NSAI performed an independent engineering evaluation in accordance with the definitions and regulations of the SEC to obtain an independent estimate of the Company's proved reserves and future net revenues.

5. Third Party Procedures and Methods Review

The review consisted of 33 fields which included the Company's major assets in the United States and encompassed 100 percent of the Company's proved reserves and future net cash flows as of December 31, 2014, 2013, and 2012. The principal engineer presented the outside engineering firm with an overview of the data, methods and assumptions used in estimating reserves and future net revenues for each field. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating expenses and other relevant economic criteria.

6. Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures from the FASB concerning disclosures about oil and gas producing activities, and based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and oil and natural gas sales prices will probably differ from the average annual prices required to be used in these calculations;
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- A 10 percent discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and
- Future net revenues may be subject to different rates of income taxation.

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved crude oil and natural gas reserves as of year-end is shown for Exploration for fiscal years 2014, 2013 and 2012.

	December 31, 2014	December 31, 2013	December 31, 2012
Future cash inflows	$ 1,339,372,300	$ 1,450,469,000	$ 823,280,251
Future oil and natural gas operating expenses	(322,298,300)	(334,883,800)	(151,140,007)
Future development costs	(405,900,900)	(424,256,900)	(209,618,885)
Future income tax expenses	(133,467,940)	(163,704,120)	(111,946,653)
Future net cash flows	477,705,160	527,624,180	350,574,706
10% annual discount for estimating timing of cash flows	(183,249,968)	(202,270,201)	(139,021,820)
Standardized measure of discounted future net cash flows	$ 294,455,192	$ 325,353,979	$ 211,552,886

Estimates of future net cash flows from proved reserves of gas, oil, and condensate for fiscal years 2014, 2013 and 2012 are computed using the average first-day-of-the-month price during the 12-month period including the impact of cash flow hedges for 2012 and 2011 only. Since the Company discontinued cash flow hedge accounting as of January 1, 2013, the impact of cash flow hedges are excluded as of that date. Prices used in computing year-end future cash flows were $91.48, $96.94 and $94.04 for crude oil and $4.35, $3.67 and $2.93 for natural gas for fiscal years 2014, 2013 and 2012, respectively.

The ceiling test for many companies following the full cost method of accounting for oil and natural gas properties, including the Company, could be negatively impacted by prolonged unfavorable crude oil and natural gas prices. Future operating expenses and development costs are computed primarily by the Company's petroleum engineer by estimating the expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on the year-end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of ten percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

7. Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves for Exploration are summarized below:

	2014	2013	2012
Changes due to current year operation:			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (25,270,455)	$ (17,255,824)	$ (13,250,556)
Extensions and discoveries	2,743,800	37,750,617	40,013,415
Purchases of oil and gas properties	12,827,533	215,427,459	177,412,984
Development costs incurred during the period that reduced future development costs	9,178,400	100,500	5,432,652
Changes due to revisions in standardized variables:			
Prices and operating expenses	(42,125,763)	(30,773,529)	(37,028,314)
Income taxes	19,303,313	(38,340,467)	(40,922,146)
Estimated future development costs	7,218,529	32,430,504	(5,173,677)
Quantity estimates	(21,028,476)	(107,070,514)	(12,905,019)
Sale of reserves in place	-	-	-
Accretion of discount	43,124,820	27,910,664	11,055,659
Production rates, timing and other[1]	(36,870,488)	(6,378,317)	1,834,021
Net change	(30,898,787)	113,801,093	126,469,019
Beginning of year	325,353,979	211,552,886	85,083,867
End of year	$ 294,455,192	$ 325,353,979	$ 211,552,886

[1] For 2014, the approximate effect of timing changes is $28.5 million, leaving the remaining value as other differences of approximately $8.4 million.

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pretax discounted basis.

Exhibit 21.1

List of Subsidiaries

The Yuma Companies, Inc.
Yuma Exploration and Production Company, Inc.
Texas Southeastern Gas Marketing Company
Yuma Petroleum Company
Pyramid Oil LLC
Pyramid Delaware Merger Subsidiary, Inc.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 30, 2015, with respect to the consolidated financial statements included in the Annual Report of Yuma Energy, Inc. on Form 10-K for the year ended December 31, 2014. We hereby consent to the incorporation by reference of said report in the Registration Statements of Yuma Energy, Inc. on Form S-3 (File No. 333-192094, effective November 21, 2013); on Form S-4 (File No. 333-197826, effective August 8, 2014); and on Forms S-8 (File No. 333-175706, effective July 21, 2011 and File No. 333-201210, effective December 22, 2014).

/s/ Grant Thornton LLP

Houston, Texas
March 30, 2015

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Annual Report on Form 10-K of Yuma Energy, Inc. for the year ended December 31, 2014, of our report dated March 17, 2015, with respect to estimates of reserves and future net revenue of Yuma Energy, Inc., as of December 31, 2014, and to all references to our firm included in this Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
March 30, 2015

Exhibit 31.1

Certification

I, Sam L. Banks, certify that:

1. I have reviewed this Annual Report on Form 10-K of Yuma Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ Sam L. Banks
Sam L. Banks
Principal Executive Officer
March 30, 2015

Exhibit 31.2

Certification

I, Kirk F. Sprunger, certify that:

1. I have reviewed this Annual Report on Form 10-K of Yuma Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Kirk F. Sprunger
Kirk F. Sprunger
Principal Financial Officer
March 30, 2015

Section 1350 Certification

I, Sam L. Banks, certify that:

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

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Sam L. Banks
Sam L. Banks
President and Chief Executive Officer
March 30, 2015

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Section 1350 Certification

I, Kirk F. Sprunger, certify that:

In connection with the Annual Report on Form 10-K of Yuma Energy, Inc. (the “Company”) for the fiscal year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kirk F. Sprunger, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Kirk F. Sprunger
Kirk F. Sprunger
Chief Financial Officer
March 30, 2015

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

March 17, 2015

Mr. Sam L. Banks
Yuma Exploration and Production Company, Inc.
1177 West Loop South, Suite 1825
Houston, Texas 77027

Dear Mr. Banks:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2014, to the Yuma Exploration and Production Company, Inc. (Yuma) interest in certain oil and gas properties located in California, Louisiana, North Dakota, Oklahoma, and Texas. We completed our evaluation on or about January 22, 2015. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Yuma. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Yuma Energy Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Yuma interest in these properties, as of December 31, 2014, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,494.8	132.0	3,422.5	96,487.9	66,839.4
Proved Developed Non-Producing	540.1	180.6	4,364.0	42,676.1	27,791.6
Proved Undeveloped	9,497.2	2,166.6	27,473.0	472,009.1	286,415.1
Total Proved	11,532.2	2,479.2	35,259.5	611,173.1	381,046.1

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. One well included in the proved developed producing category, the Crosby 14-1 in Masters Creek Field, produced in December 2014, was shut in for 30 days, and was returned to production in early January 2015. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Yuma's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Yuma's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil and NGL volumes, the average West Texas Intermediate posted price of $91.48 per barrel is adjusted by lease for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $4.350 per MMBTU is adjusted by lease for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $94.84 per barrel of oil, $34.67 per barrel of NGL, and $4.531 per MCF of gas.

Operating costs used in this report are based on operating expense records of Yuma. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Yuma are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Yuma and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Yuma's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Yuma interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Yuma receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Yuma, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Yuma, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. G. Lance Binder, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1983 and has over 5 years of prior industry experience. Philip R. Hodgson, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:/s/ G. Lance Binder
G. Lance Binder, P.E. 61794
Executive Vice President

Date Signed: March 17, 2015

By: /s/ Philip R. Hodgson
Philip R. Hodgson, P.G. 1314
Vice President

Date Signed: March 17, 2015

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

GLB:SDB

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those 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.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.