SARATOGA RESOURCES INC /TX
Form 10-K
April 15, 2015

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2014

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

For the transition period from ____________ to _____________

Commission File No. 1-32955

SARATOGA RESOURCES, INC.

(Exact name of registrant specified in its charter)

Texas	**76-0314489**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

9225 Katy Freeway, Suite 100, Houston, Texas 77024
(Address of principal executive offices)(Zip code)

Issuer's telephone number, including area code: (713) 458-1560

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

Title of each class	Name of each exchange on which each is registered
Common Stock, $0.001 par value	NYSE MKT

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

None
(Title of Class)

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

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

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 ý No o

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 ý No ¨

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

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

Large accelerated filer o Accelerated filer o Non-accelerated filer o Smaller reporting company ý

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2014, based on the closing sales price of the registrant s common stock on that date, was approximately $27.3 million. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 5% or more of the outstanding common stock have been excluded from this computation in that such persons may be deemed to be affiliates.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

The number of shares of the registrant s common stock, $0.001 par value, outstanding as of April 10, 2015 was 30,986,601.

DOCUMENTS INCORPORATED BY REFERENCE

None

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

3-D seismic Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two dimensional, seismic.

anticline An arch-shaped fold in rock in which rock layers are upwardly convex. The oldest rock layers form the core of the fold, and outward from the core progressively younger rocks occur.

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

Bcf One billion cubic feet of natural gas.

behind pipe Reserves which are expected to be recovered from zones behind casing in existing wells, which require additional completion work or a future recompletion prior to the start of production.

Boe Barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boepd Boe per day.

Bopd Bbls of oil (or condensate) per day.

Btu One British thermal unit.

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.

condensate Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.

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

drilling locations Total gross locations specifically quantified by management to be included in the company s multi-year drilling activities on existing acreage. The company s actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.

dry hole An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

exploratory well A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

farm-in An agreement between a participant who brings a property into the venture and another participant who agrees to spend an agreed amount to explore and develop the property and has no right of reimbursement but may gain a vested interest in the venture. A farm-in describes the position of the participant who agrees to spend the agreed-upon sum of money to gain a vested interest in the venture.

field An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

formation An identifiable layer of rocks named after its geographical location and dominant rock type.

gross wells Total number of producing wells in which we have an interest.

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held by production or *HBP* A provision in an oil and gas lease that perpetuates a company s right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or gas.

Henry Hub The pricing point for natural gas futures contracts traded on the NYMEX.

HLS Heavy Louisiana Sweet crude oil, being a high quality low-sulfur content low API gravity, high viscosity premium crude oil.

lease A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.

leasehold Mineral rights leased in a certain area to form a project area.

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

LLS Light Louisiana Sweet crude oil, being a high quality low-sulfur content high API gravity low viscosity premium crude oil.

MBbl One thousand barrels of oil or other liquid hydrocarbons.

MBoe Thousand barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MBoepd Thousand barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids per day.

Mcf One thousand cubic feet of natural gas.

Mcfpd Mcf per day.

MMBbl One million barrels of oil or other liquid hydrocarbons.

MMBoe Million barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

net acre Fractional ownership working interest multiplied by gross acres. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

net revenue interest A share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest. It is the percentage of production that each party actually receives.

net wells The sum of our fractional interests owned in gross wells.

NGLs Natural gas liquids.

NYMEX The New York Mercantile Exchange.

overriding royalty interest A right to receive revenues, created out of the working interest, from the production of oil and gas from a well free of obligation to pay any portion of the development or operating costs of the well and limited in life to the duration of the lease under which it is created.

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

PDP Proved developed producing.

PDNP Proved developed nonproducing.

plugback To shut off lower formation in a well bore.

plugging and abandonment Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

possible reserves Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

probable reserves Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

production Natural resources, such as oil or gas, taken out of the ground.

productive well A well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

prospect A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

proved developed non-producing reserves (PDNP) Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods that are not currently being produced.

proved developed producing reserves (PDP) Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and that are currently being produced.

proved reserves Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped. If deterministic methods are used, the term reasonable certainty is intended to express 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.

proved undeveloped reserves (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.

PV-10 The discounted present value of the estimated future gross revenue to be generated from the production of proved oil and gas reserves (using pricing assumptions consistent with, and after deducting estimated abandonment costs to the extent required by, SEC guidelines), net of estimated future development and production costs, before income taxes and without giving effect to non-property related expense, discounted using an annual discount rate of 10% and calculated in a manner consistent with SEC guidelines.

recompletion After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well s productivity.

reserve life A measure of the productive life of an oil and gas property or a group of properties, expressed in years.

reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

royalties The portion of oil and gas retained by the lessor on execution of a lease or the cash value paid by the lessee to the lessor based on a percentage of the gross production from the leased property free and clear of all costs except taxes.

sand A geological term for a formation beneath the surface of the earth from which hydrocarbons are produced. Its make-up is sufficiently homogenous to differentiate it from other formations.

shut-in To close valves on a well so that it stops producing; said of a well on which the valves are closed.

standardized measure The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

stratigraphic trap A variety of sealed geologic container capable of retaining hydrocarbons, formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

successful A well is determined to be successful if it is producing oil or natural gas, or awaiting hookup, but not abandoned or plugged.

through-tubing Pertaining to a range of products, services and techniques designed to be run through, or conducted within, the production tubing of an oil or gas well. The term implies an ability to operate within restricted-diameter tubulars and is often associated with live-well intervention since the tubing is in place.

trap A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.

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 The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

workover The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

WTI West Texas Intermediate crude oil, being light, sweet crude oil with high API gravity and low sulfur content used as a benchmark for U.S. crude oil refining and trading.

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. These forwarding-looking statements include without limitation statements regarding our expectations and beliefs about the market and industry, our goals, plans, and expectations regarding our properties and drilling activities and results, our intentions and strategies regarding future acquisitions and sales of properties, our intentions and strategies regarding the formation of strategic relationships, our beliefs regarding the future success of our properties, our expectations and beliefs regarding competition, competitors, the basis of competition and our ability to compete, our beliefs and expectations regarding our ability to hire and retain personnel, our beliefs regarding period to period results of operations, our expectations regarding revenues, our expectations regarding future growth and financial performance, our beliefs and expectations regarding the adequacy of our facilities, and our beliefs and expectations regarding our financial position, ability to finance operations and growth and the amount of financing necessary to support operations. These statements are subject to risks and uncertainties that could cause actual results and events to differ materially. See Item 1A. Risk Factors for a discussion of certain risks. We undertake no obligation to update forward-looking statements to reflect events or circumstances occurring after the date of this annual report on Form 10-K.

As used in this annual report on Form 10-K, unless the context otherwise requires, the terms we, us, the Company, Saratoga and Saratoga Resources refer to Saratoga Resources, Inc., a Texas corporation, and its subsidiaries.

PART I

Item 1.

Business

General

We are an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of crude oil and natural gas properties. As of December 31, 2014, our properties consisted of approximately 51,500 acres under lease, including 31,700 acres gross/net located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana and 19,800 acres gross/net under federal leases in the shallow Gulf of Mexico shelf.

Our state and parish leases span 11 fields which are characterized by over 30 years of development drilling and production history, including Grand Bay field which has over 70 years of production history and over 258 MMBoe produced to date, yet remains virtually unexplored at depths greater than 15,000 feet. Substantially all of our state and parish leases are held by production (HBP) without near-term lease expirations. Most of those properties offer multiple stacked reservoir objectives with substantial behind pipe potential.

Our shallow Gulf of Mexico shelf properties were acquired during 2013. At December 31, 2014, our shallow Gulf of Mexico shelf properties did not include any producing wells and we were engaged in efforts to seek partners to participate in development of such properties. We continually seek to enhance our acreage position through leasing and evaluation of opportunistic acquisitions primarily within, but not limited to, the transition zone and in the shallow Gulf of Mexico.

As of December 31, 2014, our total proved reserves were 10.2 MMBoe, consisting of 5.8 MMBbls of oil and 26.6 Bcf of natural gas, approximately 73% of which was attributable to state and parish properties. The PV-10 of our proved reserves at December 31, 2014 was $209.3 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $69.4 million. Additionally, we had probable reserves of 25.9 MMBoe, consisting of 10.4 MMBbls of oil and 93.2 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities. We operate over 99% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

During 2014, we produced 670.1 MBoe, of which approximately 76% was oil and all of which was attributable to our state and parish properties. As of December 31, 2014, our development opportunities included 61 proved behind pipe and shut-in opportunities in 44 wells in 6 fields, 36 proved undeveloped opportunities within 15 proposed wells in 5 fields. An additional 61 formerly proved undeveloped opportunities within 21 proposed wells in 3 fields were re-classified as probable P90 reserves as required by the SEC five-year PUD rule. Additionally, at December 31, 2014, we had 37 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2014, 41 probable undeveloped opportunities within 24 proposed wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 86 possible undeveloped opportunities within 33 wells in 5 fields. During the year ended December 31, 2014, we successfully completed one development well, 6 recompletions, and 9 workovers.

Our principal and administrative offices are located at 9225 Katy Freeway, Suite 100, Houston, Texas. Our telephone number is (713) 458-1560.

Our Strengths

High-Quality Resource Base. Our principal assets are located in shallow waters on parish and state leases of south Louisiana in fields that are characterized by over 30 years of development drilling and production history. These assets are in close proximity to several other fields operated by leading industry companies such as Energy XXI Limited, Helis Oil and Gas Company, Hilcorp Energy Company, Swift Energy Company and Texas Petroleum Investment Company. Additionally, our shallow Gulf of Mexico shelf assets include proved reserves and prospects identified by 3-D seismic and are located in proximity to existing field infrastructure. We believe the quality and location of our properties reduce our development risk and promote operating efficiencies which help to reduce our lifting costs. Additionally, the oil produced by our assets currently commands a premium to WTI crude oil pricing. We also believe that our reserve base has significant undeveloped and exploratory drilling opportunities.

Geographically Focused Assets Without Exposure to Deep Water Operating Risks. Our proved reserves are primarily located in the shallow waters of the Grand Bay Field, Breton Sound 32 Field and 11 other fields on state and parish leases of south Louisiana and, to a lesser degree, in the shallow waters of the Gulf of Mexico shelf. This focused asset base allows us to leverage our technical knowledge of the geological features and operating dynamics within this region. Our geographic focus also enables us to establish economies of scale in both drilling and production operations, allowing us to manage a greater amount of acreage and minimize the marginal costs associated with development activities. Because our present operations are primarily in shallow state waters and, to a lesser extent, in the shallow Gulf of Mexico shelf, we are not exposed to the extreme risk associated with deep water operations. In addition, we are able to avoid the long lead times to first production and ultra-high costs associated with deep water development.

Extensive Workover and Drilling Inventory. At December 31, 2014, we controlled approximately 51,500 gross/net acres, of which more than half is HBP. Approximately 81% of our proved reserves are classified as proved developed nonproducing and proved undeveloped reserves. We believe our properties hold substantial additional behind pipe reserves beyond the amounts quantified in the proved reserves category and provide us with a significant number of exploration prospects. As of December 31, 2014, our development opportunities included 61 proved behind pipe and shut-in opportunities in 44 wells in 6 fields, 36 proved undeveloped opportunities within 15 proposed wells in 5 fields. An additional 61 formerly proved undeveloped opportunities within 21 proposed wells in 3 fields were reclassified as probable P90 reserves as required by the SEC five year PUD rule. Additionally, at December 31, 2014, we had 37 probable behind pipe and shut-in development opportunities, 41 probable undeveloped opportunities within 24 proposed wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 86 possible undeveloped opportunities within 33 wells in 5 fields.

High Net Revenue Interests and Operational Control. We own an average net revenue interest in our properties of approximately 75%, which enhances our returns by reducing royalty payments and provides us flexibility in negotiating potential farm-outs, joint ventures, and other opportunities. Additionally, we own a 100% working interest in substantially all of our properties and operate over 99% of the wells that comprise our PV-10 as of December 31, 2014. As an operator, we can more efficiently manage our operating costs, capital expenditures and the timing and method of development of our properties. Our significant operational control and expertise in the area should allow us to operate with a lower cost structure and maximize returns on capital employed.

Control of Infrastructure and Third-Party Processing Revenues. Our extensive infrastructure assets include six production platforms and over 100 miles of pipeline, mostly within the Main Pass and Breton Sound areas. Our infrastructure assets enhance our ability to expand our existing resource base through joint ventures with, and acquisitions of, neighboring producing properties and to generate revenues from third-party handling and processing.

Experienced Management Team. Our directors and executive officers have over 270 combined years of industry experience and a proven track record of successfully leading independent oil and natural gas companies. In addition, our management team has extensive major oil company operational expertise with particular emphasis on cost-control and reservoir management.

Our Strategy

We intend to use our competitive strengths to increase our reserves, production and cash flow. The following are key elements of our strategy:

Grow Through Exploitation, Development and Exploration of Our Properties. We believe that our extensive HBP acreage position will allow us to grow organically through lower-risk development drilling and recompletion work. We have attractive opportunities to expand our reserve base through field extensions, delineating shallower and deeper formations within existing fields and exploratory drilling. Most of our locations offer multiple stacked reservoir objectives with substantial behind pipe potential. We intend to focus our efforts on exploiting our inventory of opportunities with a view to growing our production through a combination of field optimization efforts, including infrastructure upgrades, and conversion of PDNP and proved undeveloped reserves to PDP, and through participation via farm-outs or promoted deals in development of our acreage on the Gulf of Mexico shelf. Development work is expected to be spread over several fields. In order to enhance our organic growth initiatives, we have made significant investments in, and will continue to invest in, our infrastructure to support increased handling capacity and create operating efficiencies to lower handling and other operating costs.

Actively Manage the Risks and Rewards of Our Drilling Program. We operate over 99% of the wells that comprise our proved reserves as of December 31, 2014, and we own net revenue interests in our properties that average approximately 75% on a net acreage leasehold basis. We believe operating our properties is important because it allows us to control the timing and costs in our drilling budget, as well as control operating costs and production marketing. In addition, our high net revenue interests enhance our returns from each successful well we drill by generating a higher percentage of cash flow. We believe our high net revenue interests provide us with a unique opportunity to retain a substantial economic interest in riskier wells, including wells that may be drilled on the Gulf of Mexico shelf acreage, while mitigating the risk associated with these projects through farm-outs or promoted deals. Additionally, we will review and rationalize our properties on a continuous basis in order to optimize our existing asset base.

Leverage Technological Expertise. We believe that 3-D seismic analysis and other advanced technologies and production techniques are useful tools that help improve drilling results and ultimately enhance our production and returns. At December 31, 2014, we either owned or held licenses for 3-D seismic data covering over 90 square miles in Grand Bay and other fields. We intend to utilize these technologies and production techniques in exploring for, developing and exploiting oil and natural gas properties to help us reduce drilling risks, lower finding costs and provide for more efficient production of oil and natural gas from our properties. We believe that the use of these technologies enhances our probability of locating and producing reserves that might not otherwise be discovered.

We have conducted and will continue to complete full field studies over all of our properties. Such field studies include an exhaustive review and integration of well data, wellbore utilization analysis, incorporation of 3-D seismic interpretation results and detailed geological mapping of each sand.

Optimize Development Results and Well Production Through Identification and Development of Horizontal and High Angle Prospects. As a result of our exhaustive field studies, and based on initial drilling results, we believe that our assets offer opportunities to optimize our investment of development capital and resulting production through focusing on the identification and development of horizontal and high angle prospects. Consistent with limited historical horizontal development activities on our properties, we undertook our first horizontal and high angle wells during 2013 with favorable results. We intend to capitalize on our experience in such wells to identify and develop additional horizontal and high angle prospects going forward and, based on results to date, expect to see improved well economics on such prospects.

Pursue Opportunistic Acquisitions. We are an opportunity driven company and, to that end, evaluate potential acquisitions that are compatible with and enhance our growth objectives. We continually review opportunities to acquire producing properties, leasehold acreage and drilling prospects. In addition to a large inventory of exploration prospects within our HBP lease position, we have identified a large inventory of exploration prospects in unleased state acreage in close proximity to our existing infrastructure in the Main Pass and Breton Sound areas and shallow Gulf of Mexico shelf acreage that we may pursue in the near future. When identifying acquisition candidates, we focus primarily on underdeveloped assets with significant growth potential that we believe will allow us to enhance and exploit properties without assuming significant geologic, exploration or integration risk.

Properties

The following table describes our properties, proved reserves and production profile at December 31, 2014:

Property	Barrels of Oil Equivalent (MBoe)	% Oil		PV-10(1) (in thousands)	Net Acreage (estimated)	Net Revenue Interest %	Net Producing Wells	Reserve Life Index(2) (Years)
Louisiana Transition Zone								
Grand Bay	3,425	71%	$	88,084	17,391	70-79%	58	15.5
Breton Sound 32	1,698	68%	$	38,454	3,117	78-82%	14	10.4
Breton Sound 18	900	60%	$	28,833	1,866	78-79.5%	5	6.4
Other	1,462	27%	$	19,546	9,323	69-81%	18	7.0
Gulf of Mexico Shelf								
Vermillion	1,071	79%	$	20,223	9,814	77%	0	*
Ship Shoal	1,666	25%	$	14,145	10,000	77%	0	*
All Properties	**10,222**	**57%**	**$**	**209,285**	**51,511**	**69-81%**	**95**	**13.9**

*

Not meaningful

(1)

Based on unweighted average benchmark prices as of the first of each month during 2014 of $94.99 per Bbl and $4.35 per MMBtu and before future income taxes. The average realized price after applying differential to unweighted average benchmark prices was $96.30 per Bbl and $4.47 per Mcf. PV 10 is a non GAAP financial measure as defined by the SEC.

(2)

Calculated by dividing total net proved reserves by current net production for December 2014.

Louisiana Transition Zone

Our principal producing properties are located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana, an area commonly referred to as the transition zone. The majority of those properties were acquired in, and we have operated those properties since, 2008. Our properties in the transition zone span 11 fields with principal properties, by production and reserves, being in Grand Bay, Breton Sound 18 and Breton Sound 32 fields.

Grand Bay Field. The Grand Bay Field is located in Plaquemines Parish, approximately 70 miles southeast of New Orleans, Louisiana. It is situated in the transitional coastline in a protected in-bay environment on parish and state leases on the east side of the Mississippi River. Gulf Oil discovered the field in 1938. Saratoga is the operator of all of the Grand Bay Field with 100% working interest and net revenue interests ranging from70% to 79%. Our leases in the Grand Bay Field, which are all HBP, cover an estimated 17,391 gross and net acres.

The Grand Bay Field is a large, faulted anticlinal structure. It lies on a northwest/southeast trending, deep-seated salt ridge that also sets up Coquille Bay Field, to the northwest, and Romere Pass Field, to the southeast. Trapping is predominantly from intersecting fault closures associated with this anticlinal feature, although there are cases of stratigraphic trapping. The predominant drive mechanism is water drive. Some productive formations are clean, blocky sands with high-resistivity pay. Other laminated, low-resistivity sands are also productive. Shallow sands are predominantly gas-filled and associated with anomalous amplitudes. There are additional shallow amplitudes in the field that have not yet been drilled or logged.

The Grand Bay field has produced oil and gas from over 65 different sand formations located at depths between approximately 1,600 and 13,500 feet. Our field holdings include approximately 66 active wellbores, 50 proved developed nonproducing opportunities and 23 proved undeveloped opportunities in 8 proposed drilling locations within the field. An additional 48 formerly proved undeveloped opportunities within 14 proposed wells were reclassified as probable P90 reserves as required by the SEC five year PUD rule. There are also 28 probable developed nonproducing, 27 probable undeveloped opportunities in 18 proposed drilling locations, 12 possible developed nonproducing and 41 possible undeveloped opportunities in 16 proposed drilling locations within the field. We are planning to undertake one or more reservoir simulations in the field in 2015. Based on one previous horizontal well drilled in Grand Bay field, with favorable results, we are actively seeking horizontal and high angle well candidates in Grand Bay field. Another important part of our ongoing analysis of Grand Bay is the geopressured sequence incorporating the Tex L (25 sand) and Cib Carst (43 sand) reservoirs, below 13,000 feet, which has been largely unexplored to date. We have identified multiple opportunities within the sequence and will continue our efforts to seek third parties to drill the initial prospect within the sequence once commodity prices recover.

We own a license to 90 square miles of proprietary 3-D seismic data relating to the Grand Bay Field, which was originally acquired by Greenhill in 1994 and reprocessed by Saratoga in 2008, 2010, 2012 and 2013. We expect to use this dataset to better locate proposed development wells and deep oil and gas targets below existing production.

Facilities include a central compressor station, four tank batteries, numerous gas lift manifolds and a bunk house, from which all field operations are controlled. Low pressure, high Btu-content gas at Grand Bay Field is used to lift oil and high pressure, lower Btu-content gas. We continue to look for ways to decrease operating costs in all fields.

Breton Sound Block 32 Field. Breton Sound Block 32 field is located in Plaquemines Parish, Louisiana, approximately 45 miles ESE of New Orleans, Louisiana. It is situated in the transitional coastline in a protected in-bay environment on parish and state leases on the east side of the Mississippi River. The field was discovered by Barnsdall in 1949 but most of the field development was undertaken by Kerr-McGee who sold the field to LLOG who, in turn, sold the field to Amerada Hess. Saratoga acquired its interest from Amerada Hess in September 2006. Saratoga operates the field with 100% WI. There are two principal HBP leases associated with the field, SL 1227 and SL 15536 plus an additional 9 HBP leases and an additional primary term lease, SL 21247, associated with a deeper Tex W objective with shallow PUD reserves.

Breton Sound Block 32 field is a broad, low-relief anticlinal structure with rollover into a large west-east trending down-to-the-south fault. The reservoir drive mechanisms are water drive for the principal 5750 and 5800 sands and combination water drive/pressure depletion for other reservoirs. Production has been from between approximately 5,300' and 11,500', subsea. Our field holdings include approximately 17 active wellbores and 5 proved undeveloped opportunities in 3 proposed drilling locations within the field. There are also 2 probable developed nonproducing, 4 probable undeveloped opportunities in 1 proposed drilling location and 5 possible undeveloped opportunities in 4 proposed drilling locations within the field. Saratoga has successfully drilled and completed 3 horizontal wells in the field since 2013 and plans more horizontal development wells once the results of its reservoir simulation project have been analyzed in the first half of 2015.

Facilities include a centrally-located, manned, platform complex in 10 feet of water to which wells are tied back subsea. Production from the field is transported approximately 2 miles to the NW via Saratoga-owned flowlines to where it ties into a 20 sales line. We have licensed a high-quality 3-D seismic survey that covers the field and we have undertaken seismic reprocessing of these data to enhance data quality.

During 2014, we drilled and completed the Rocky 3 horizontal development well in Breton Sound 32 field which targeted an elongated ridge in the 5,800 sand with a 750 lateral completion.

Breton Sound Block 18 Field. The Breton Sound Block 18 Field is located in Plaquemines Parish, Louisiana, approximately 45 miles east-southeast of New Orleans, Louisiana. It is situated in the transitional coastline in a protected in-bay environment on parish and state leases on the east side of the Mississippi River. The older field proper was discovered in 1963. The newer portion of the field, where Saratoga's interests are located, was discovered in 2000 by LLOG, who sold the field to Amerada Hess. Saratoga acquired their interest from Amerada Hess in September 2006. Saratoga owns 100% and is the operator. There are 7 HBP leases associated with the field and one primary term lease.

The Breton Sound Block 18 Field is a faulted, anticlinal structure, with outlying stratigraphic traps. It is one of a series of stratigraphic trap-type fields in the eastern Louisiana coastal offshore Middle Miocene trend that was discovered with 3-D seismic technology. The reservoir drive mechanisms are water drive and combination water drive/pressure depletion. Production has been between approximately 3,500' and 9,700', subsea.

Facilities include a centrally-located, unmanned, platform in 10 feet of water to which wells are tied back subsea. Production from the field is transported to the Breton Sound Block 32 Field. We have licensed a high-quality 3-D seismic survey that covers the field and we have undertaken seismic reprocessing of these data to enhance data quality.

Other Fields. We hold interests in 10 other fields, 8 of which are located in shallow waters on state leases in Plaquemines, St. Bernard and St. Mary parishes of southern Louisiana and 2 of which are in the shallow waters of the Gulf of Mexico. We have 100% working interest in all fields, except for the Main Pass 47 Field, where we have a 7.5% overriding royalty interest in one producing well. Our net revenue interests in these fields average 75%. The leases, which are mostly HBP, cover 29,137 gross/net acres.

Among the other fields in which we hold interests are the Main Pass Block 25, Main Pass Block 46, Main Pass Block 52 and Vermilion Block 16 fields. We operate all these fields with a 100% working interest. We have unmanned platforms at each of these fields and wells are tied back subsea to our facilities.

There appears to be renewed interest in the high profile, ultra-deep play following Freeport-McMoRan s recent onshore success at their Highlander Prospect so we will continue to evaluate the ultra-deep potential underlying our Grand Bay and Vermilion Block 16 fields.

Gulf of Mexico Shelf.

In July 2013, final leases were awarded pursuant to our high bid on four leases, with seismic maps included, totaling 19,814 acres in the Central Gulf of Mexico Lease Sale 227. The acreage is in the shallow Gulf of Mexico shelf in water depths of 13 to 77 feet. Two of the leases are in the Vermilion area and two of the leases are in the Ship Shoal area. The leases have a primary term of five years and can be extended for an additional three years. Lease bonuses on the prospects totaled $880,000 and we paid a prospect fee of $500,000 to a third party consultant. The cost of the leases, in the amount of $1,380,000, has been recorded in oil and gas properties. Annual rentals on the leases total $138,698 during the primary term.

Using licensed 3-D surveys, four initial prospects, two of which have proved undeveloped reserves, have been identified within the Gulf of Mexico shelf acreage. With the drop in commodity prices during the second half of 2014, we have put efforts to drill those prospects on hold. We expect to resume efforts to seek partners to drill the first of the prospects at such time as commodity prices support such efforts. The acreage includes proved undeveloped reserves at December 31, 2014 of 2.74 MMBOE.

Field Infrastructure

We own significant infrastructure assets that are used to service our properties and third-party customers, including over 100 miles of pipeline connecting several of the fields as well as outlying wellheads. There are five platform facilities plus 35 active producing wellbores associated with the Main Pass and Breton Sound fields and one platform plus two active producing wellbores at Vermilion Block 16 field. Facilities at the Grand Bay Field include four tank batteries, a compressor station, various flow lines and a bunk house and there are 58 active producing wellbores in the field. In addition to serving our wells and improving field economics, we generate processing and production handling revenues from third-party customers. We also operate approximately eight saltwater disposal wells.

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2014, our estimated net proved oil and natural gas reserves, the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (PV-10) and after future income taxes (Standardized Measure) of our proved reserves and our estimated net probable and possible oil and natural gas reserves, each prepared in accordance with assumptions prescribed by the Securities and Exchange Commission (SEC). All of our reserves are located in the United States.

The PV-10 value is a widely used measure of value of oil and natural gas assets and represents a pre-tax present value of estimated cash flows discounted at ten percent. PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the estimated discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies because of differences in the amounts and timing of deductible basis, net operating loss carry-forwards and other factors. We believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and is not intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

Reserve category	Oil (MBbls)	Reserves[1] Natural Gas (MMcf)		Total[2] (MBoe)
Proved				
Developed				
Producing	1,666	1,638		1,940
Shut-in	53	352		112
Behind Pipe	1,179	3,215		1,714
Total Proved Developed	2,898	5,205		3,766
Undeveloped	2,894	21,374		6,456
Total Proved	5,792	26,579		10,222
Probable[3]				
Developed	987	6,156		2,013
Undeveloped	9,396	87,089		23,911
Possible[3]				
Developed and Undeveloped	16,793	121,991		37,125
PV-10[1] (in thousands) of proved			$	209,285
Standardized Measure[4] (in thousands)			$	188,795

____

(1)

In accordance with applicable financial accounting and reporting standards of the SEC, the estimates of our proved reserves and the PV-10 set forth herein reflect estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2014. For purposes of determining prices, we used the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ended December 31, 2014 which were $94.99 per Bbl and $4.35 per MMBtu. The prices utilized for purposes of estimating our proved reserves were $96.30 per Bbl and $4.47 per Mcf, after adjustment by property for energy content, quality, transportation fees and regional price differentials. The prices should not be interpreted as a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

(2)

Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(3)

Probable and possible reserves have not been discounted for the risk associated with future recovery.

(4)

The Standardized Measure differs from PV-10 only in that the Standardized Measure reflects estimated future income taxes.

Due to the inherent uncertainties and the limited nature of reservoir data, proved, probable and possible reserves are subject to change as additional information becomes available. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

In estimating probable and possible reserves, it should be noted that those reserve estimates inherently involve greater risk and uncertainty than estimates of proved reserves. While analysis of geoscience and engineering data provides reasonable certainty that proved reserves can be economically producible from known formations under existing conditions and within a reasonable time, probable reserves involve less certainty with reserves supporting a probable classification from a probabilistic analysis where those reserves are as likely as not to be recovered. Possible reserves involving even less certainty than probable reserves and possible classification is supported when there is at least a 10% probability that total quantities recovered equal or exceed proved plus probable plus possible reserve estimates.

Alternative Pricing Case. We use forward-looking market-based data in developing our drilling plans, assessing our capital expenditure needs and projecting future cash flows. The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income taxes using the 2014 12-month average prices reflected in our reported reserve estimates and the NYMEX future strip prices as of December 31, 2014.

	Oil	Gas	Total	PV-10
	(MBbls)	**(MMcf)**	**(MBoe)[1]**	**(in thousands)**
SEC Case	5,792	26,579	10,222	$ 209,285
NYMEX Strip Price Case[2]	4,829	24,720	8,945	$ 69,368

(1)

Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(2)

The NYMEX Strip Pricing Case discloses our estimated proved reserves using future market-based commodities prices instead of the average historical prices used in the SEC Case. Under the NYMEX Strip Pricing Case, we used futures prices, as quoted on the New York Mercantile Exchange (NYMEX) on December 31, 2014, as benchmark prices for 2015 through 2022, and continued to use the 2022 futures price for all subsequent years. These benchmark prices were further adjusted for quality, energy content, transportation fees and other price differentials specific to our properties, resulting in an average adjusted price of $67.58 per barrel of oil and $3.84 per Mcf of natural gas over the remaining life of the proved reserves. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 and Standard Measure estimates, set forth above were prepared by Collarini Associates for our transition zone reserves (83.6% of PV-10 of our total proved reserves) and internally for our Gulf of Mexico shelf reserves (16.4% of PV-10 of our total proved reserves).

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

We maintain an internal staff of engineering and geoscience professionals that prepare and review internal reserve estimates and work with third-party engineering firms in the preparation of their reserve estimates, all under the leadership and direction of our President, a degreed petroleum geologist/geophysicist with over 30 years of technical experience involving petroleum reserve assessment and estimation and geoscience-based evaluation. Our technical staff works closely with Collarini Associates (the outside reserve engineers) in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy and timeliness of the methods and assumptions used in this process. Our technical team members meet with outside reserve engineers periodically throughout the year to discuss the assumptions and methods used in the reserve estimation process. We provide historical information to the outside reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our engineering and geosciences staff coordinate with our accounting and other departments to provide the appropriate data to the outside reserve engineers in support of the reserve estimation process and to assure that information derived from the outside reserve engineers reports is properly disclosed in our reports.

Collarini Associates is an independent Houston and New Orleans-based professional engineering firm specializing in technical and financial evaluation of oil and gas assets. Their report with respect to our transition zone reserves was prepared under the direction of Collarini Associates President and Engineering Manager, Mitch Reece. Mr. Reece holds a B.S. in petroleum engineering from Texas A&M University, is a registered professional engineer and has approximately 30 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management.

The SEC s rules with respect to technologies that a company can use to establish reserves, effective for years ending after December 31, 2008, allows use of techniques that have been proved 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 have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Our technical staff and our outside reserve engineers used a combination of production and pressure performance, simulation studies, offset analogies, seismic data and interpretation, geophysical logs and core data to calculate our reserves estimates.

Proved Undeveloped Reserves

Our proved undeveloped reserves accounted for approximately 63% of our total reserves at December 31, 2014. As of December 31, 2014, none of our proved reserved had been classified as proved undeveloped for more than five years and the majority of the properties for which we have proved undeveloped reserves have ongoing production from currently developed zones. The following table summarizes activity within our proved undeveloped reserve category for the years ended December 31, 2014 and 2013:

	2014	**2013**
Proved undeveloped reserves (MBoe):		
Beginning of year	12,846	12,890
Transferred to proved developed through drilling	-	728
Increase (decrease) due to evaluation reassessments and drilling results, net	1,365	(1,073)
Acquisitions (dispositions), net (1)	-	2,740
Reductions of proved undeveloped reserves aged five or more years (2)	(7,755)	(2,439)
End of year	6,456	12,846

(1)

Proved undeveloped reserves added through acquisitions during 2013 relate to Gulf of Mexico shelf acreage leased during 2013.

(2)

Represents downward revisions at December 31, 2014 and 2013 associated with SEC s five year rule under which reserves are generally to be removed from presentation as proved reserves if not developed within five years of initially being booked in the proved undeveloped category.

Our proved undeveloped reserves at December 31, 2014 were associated with our Louisiana properties (3,719 MMBoe) and our Gulf of Mexico shelf properties (2,737 MMBoe).

We incurred costs relating to the development of proved undeveloped reserves of $5.7 million and $17.3 million during 2014 and 2013, respectively.

All proved undeveloped locations are scheduled to be drilled, or otherwise converted into proved developed reserves, before the end of 2019. None of our proved undeveloped locations have been booked for longer than five years.

Production, Price and Production Cost History

The table below sets forth certain information regarding the production volumes, average prices received and average production costs associated with our sale of oil and natural gas for the three years ended December 31, 2014.

	2012	2013	2014
Net Production:			
Oil (Bbl)	676,400	603,600	511,700
Natural gas (Mcf)	2,639,500	1,198,800	950,100
Combined volumes (Boe)	1,116,317	803,400	670,050
Average sales price per Boe	$ 73.93	$ 85.51	$ 78.09
Average production cost per Boe[1]	$ 20.74	$ 30.07	$ 43.53

(1)

Average production cost per Boe excludes severance taxes.

Drilling and Development Activity

The following table summarizes our drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	2012		2013		2014	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells:						
Productive	0	0	0	0	0	0
Unproductive	0	0	0	0	0	0
Total	0	0	0	0	0	0
Developmental Wells:						
Productive	3	3	4	4	1	1
Unproductive	0	0	0	0	0	0
Total	3	3	4	4	1	1
Success Ratio (1)	100%	100%	100%	100%	100%	100%

(1)

The success ratio is calculated as follows: (total wells drilled non-productive wells wells awaiting completion)/(total wells drilled wells awaiting completion).

A well s completion is reported in the year of completion regardless of when drilling was initiated. Productive wells are wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

In addition to the wells completed, during 2014 we successfully completed 6 out of 9 recompletion and 9 out of 14 workover operations, with one workover operation still in progress at year end. During 2013 we successfully completed 17 out of 22 recompletion and 9 out of 10 workover operations.

The foregoing information should not be considered indicative of future drilling performance, nor should it be assumed that there is any necessary correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered by us. We do not own any drilling rigs and all of our drilling activities are conducted by independent drilling contractors.

At December 31, 2014, there were no wells being drilled or recompletion or workover operations being conducted.

Productive Wells

The following table sets forth information with respect to our ownership interest in productive wells, all of which are located in the United States, as of December 31, 2014:

	Gross	**Net**
Oil wells	89	88
Gas wells	16	16
Total	105	104

Productive wells are producing wells and wells mechanically capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. Wells with multiple completions are counted as one well in the table above. The total gross wells at December 31, 2014 included no wells with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth information with respect to our gross and net developed and undeveloped oil and natural gas acreage under lease as of December 31, 2014:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Louisiana Transition Zone	30,537	30,537	1,160	1,160	31,697	31,697
Gulf of Mexico Shelf	-	-	19,814	19,814	19,814	19,814
Total	30,537	30,537	20,974	20,974	51,511	51,511

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

As is customary in the oil and natural gas industry, we can generally retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which we have an interest are for varying primary terms and, if production under a lease continues from our developed lease acreage beyond the primary term, we are entitled to hold the lease for as long as oil or natural gas is produced.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production.

Marketing, Customers and Pricing

General

We derive revenue principally from the sale of oil and natural gas. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil and natural gas. We sell our oil and natural gas on the open market at prevailing market prices. The market price for oil and natural gas is dictated by supply and demand, and we cannot accurately predict or control the price we may receive for our oil and natural gas.

Marketing

Effective April 1, 2010, we entered into a Natural Gas, Crude and Processing Marketing/Administration Agency Agreement pursuant to which Transparent Energy Services, Inc. markets substantially all of our oil and natural gas production.

We generally market our oil and natural gas production under month-to-month or spot contracts.

We receive a premium price for our Light Louisiana Sweet (LLS) and Heavy Louisiana Sweet (HLS) crude oil produced. We attribute this premium pricing to the high quality and geographic location of the crude oil product. This combination of production location and crude oil quality have allowed us to sell our crude oil at prices above WTI price postings beginning in the second half of 2011 and continuing through 2014, and we anticipate that market conditions should allow us to continue to receive pricing above WTI postings into 2015.

Sales of oil and gas production to Shell Trading (US) Company and Shell Energy North America (US), L.P. (collectively Shell) and Chevron Natural Gas, Inc. and Chevron Products Company (collectively Chevron) accounted for 50% and 37% of our consolidated sales in 2014, respectively. Sales of oil and gas production to Shell and Chevron accounted for 57% and 32% of our consolidated sales in 2013, respectively. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are readily available.

Derivatives

During the third quarter of 2012, we resumed our hedging program which had previously been suspended in February 2010. We use commodity price hedging instruments to reduce our exposure to oil and natural gas price fluctuations and to help ensure that we have adequate cash flow to fund our debt service costs and future capital programs. From time to time, we may enter into futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts; however, it is our preference to utilize hedging strategies that provide downside commodity price protection without unduly limiting our revenue potential in an environment of rising commodity prices. We use hedging primarily to manage price risks and returns on certain drilling programs. Our policy is to consider hedging an appropriate portion of our production at commodity prices we deem attractive.

As of December 31, 2014, we had the following crude oil hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Strike Price	Premium	Total Bbls
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	22,500
						22,500

Koch Supply and Trading, LP is the counterparty to our present covered call option. We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparty over the term of the commodity derivatives positions.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and undeveloped acreage. Our competitors include major integrated oil and gas companies, numerous independent oil and gas companies and individuals. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources and have been engaged in the oil and gas business for a much longer time than our company. These companies may be able to pay more for productive oil and gas properties, exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Employees

As of December 31, 2014, we had 32 full time employees. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We believe our relationships with our employees are positive. From time to time, we utilize the services of independent contractors to perform various field and other services.

Regulation of the Oil and Gas Industry

The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which we operate also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

We operate various gathering systems and pipelines servicing the areas in which we operate. The United States Department of Transportation and certain governmental agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities by prescribing standards. However, based on current standards concerning transportation and storage activities and any proposed or contemplated standards, we believe that the impact of such standards is not material to our operations, capital expenditures or financial position. All of our sales of our natural gas are currently deregulated, although governmental agencies may elect in the future to regulate certain sales.

Regulations Affecting Production

The jurisdictions in which we operate generally require permits for drilling operations, drilling bonds and operating reports and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the spacing, plugging and abandonment of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production.

These laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Moreover, many jurisdictions impose a production or severance tax with respect to the production and sale of oil and natural gas within their jurisdiction. There is generally no regulation of wellhead prices or other, similar direct economic regulation of production, but there can be no assurance that this will remain true in the future.

Regulation of Transportation and Sale of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (FERC) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Interstate oil pipeline rates are typically set based on a cost of service methodology (Cost-Based Rates); however, they may also be set based on the competitive market (Market-Based Rates) or by agreement between the pipeline and its shippers (Settlement Rates). Some oil pipeline rates may be increased pursuant to an index methodology, whereby the pipeline may increase its rates up to a ceiling set by reference to the Producer Price Index for Finished Goods (unless the rate increase is shown to be substantially in excess of the actual cost increases incurred by the pipeline). Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Gathering Regulations

Section 1(b) of the federal Natural Gas Act (NGA) exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. Although FERC has not made any formal determinations with respect to any of the natural gas gathering pipeline facilities that we own, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to establish a pipeline s status as a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities, however, has been the subject of substantial litigation and, over time, FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. The classification and regulation of our gathering lines may be subject to change based on future determinations by FERC, the courts or the U.S. Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. Our gathering operations may also be subject to state ratable take and common purchaser statutes, designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. In addition, our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services, though we do not believe that we would be affected by any such action in a manner differently than other companies in our areas of operation.

Outer Continental Shelf Regulations

Our planned operations on federal oil and gas leases in the Gulf of Mexico are subject to regulation by the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM), successor agencies to the Minerals Management Service. These leases contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the Outer Continental Shelf Lands Act (OCSLA). These laws and regulations are subject to change, and many new requirements were imposed by the BSEE and BOEM subsequent to the April 2010 Deepwater Horizon incident. For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency, (the EPA), lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and removal of facilities. To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the BOEM exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. As a result of the recent bankruptcy of ATP Oil and Gas, the BOEM has indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators and may increase the amount of financial assurance required with respect to these obligations. Under certain circumstances, the BSEE, a new federal agency created to enforce compliance with safety and environmental rules applicable to OCS activities, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Environmental Regulation

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance under the Oil Pollution Act of 1990 and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

We routinely obtain permits for our facilities and operations in accordance with applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations.

The ultimate financial impact of environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on our operations. In addition, any non-compliance with such laws could subject us to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

We are committed to the protection of the environment throughout our operations and believe our operations are in substantial compliance with applicable environmental laws and regulations. We believe environmental stewardship is an important part of our daily business and will continue to make expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. The insurance coverage maintained by us provides for the reimbursement to us of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated and combined financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

The environmental laws and regulations applicable to us and our operations include, among others, the following United States federal laws and regulations:

Resource Conservation and Recovery Act, which governs the management of solid waste;

Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as Superfund);

Clean Water Act, which governs discharges to waters of the United States;

Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;

Clean Air Act, and its amendments, which govern air emissions;

Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;

Safe Drinking Water Act, which governs the underground injection and disposal of wastewater;

Endangered Species Act and Migratory Bird Treaty Act, which prohibit certain actions that adversely affect endangered or threatened species and migratory birds and their habitat;

U.S. Department of Interior and U.S. Environmental Protection Agency regulations, which impose liability for pollution cleanup and damages; and

Occupational Safety and Health Act (OSHA) and comparable state laws and regulations that establish workplace standards for the protection of the health and safety of employees.

The following is a summary of certain existing laws, rules and regulations to which our business operations are subject:

Waste Handling

The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are not currently regulated under RCRA or state hazardous waste provisions though our operations may produce waste that does not fall within this exemption. However, these oil and gas production wastes may be regulated as solid waste under state law or RCRA. It is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the Superfund Law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain 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 the hazardous substances released into the environment.

In the course of our operations, we generate wastes that may fall within CERCLA s definition of hazardous substances. Further, we currently own, lease or operate properties that have been used for oil and natural gas exploration and production for many years. Hazardous substances or petroleum may have been released on, at, under or from the properties owned, leased or operated by us, or on, at, under or from other locations, including off-site locations, where such hazardous substances or other wastes have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances, petroleum, or other materials or wastes were not under our control. These properties and the substances or materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA or analogous or other state laws. Under such laws, we could be required to remove previously disposed hazardous substances and address any resulting impacts.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, or OPA, which amends and augments the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. In addition, OPA and regulations promulgated pursuant thereto impose a variety of regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. OPA also requires certain oil and natural gas operators to develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance.

Air Emissions

The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. 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. Oil and gas operations may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants, including volatile organic compounds, nitrous oxides, and hydrogen sulfide.

Endangered Species, Wetlands and Damages to 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. 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 oil and gas exploration or production or seek damages to species, habitat, or natural resources resulting from filling or construction or releases of oil, wastes, hazardous substances or other regulated materials.

Climate Change Legislation and Greenhouse Gas Regulation

Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that determines which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities.

Moreover, in the recent past the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if ever adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states have adopted, or are in the process of adopting, similar cap-and-trade programs.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Web Site Access to Reports

Our Web site address is *www.saratogaresources.com.* We make available, free of charge on or through our Web site, our annual report, Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission. Information contained on, or accessible through, our website is not incorporated by reference into this Form 10-K.

Item 1A.

Risk Factors

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments.

Risks Related to Our Business

The nature of our business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

We engage in exploration and development drilling activities, which are inherently risky. These activities may be unsuccessful for many reasons. In addition to a failure to find oil or natural gas, drilling efforts can be affected by adverse weather conditions (such as hurricanes and tropical storms in the U.S. Gulf Coast region), cost overruns, equipment shortages and mechanical difficulties. Therefore, the successful drilling of an oil or gas well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, could cause a well to become uneconomic or only marginally economic. In addition to their costs, unsuccessful wells could impede our efforts to replace reserves.

Our business involves a variety of operating risks, which include, but are not limited to:

fires;

explosions;

blow-outs and surface cratering;

uncontrollable flows of gas, oil and formation water;

natural disasters, such as hurricanes and other adverse weather conditions;

pipe, cement, subsea well or pipeline failures;

casing collapses;

mechanical difficulties, such as lost or stuck oil field drilling and service tools;

abnormally pressured formations; and

environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharge of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses due to costs and/or liability incurred as a result of:

injury or loss of life;

severe damage to and destruction of property, natural resources and equipment;

pollution and other environmental damage;

clean-up responsibilities;

regulatory investigations and penalties;

suspension of our operations; and

repairs to resume operations.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Unlike other entities that are geographically diversified, all of our assets and operations are located in , and offshore of, South Louisiana and we do not have the resources to effectively diversify our operations or benefit from the possible spreading of risks or offsetting of losses. Our lack of diversification may:

subject us to numerous economic, competitive and regulatory developments, any or all of which may have an adverse impact upon the particular industry in which we operate; and

result in our dependency upon a single or limited number of hydrocarbon basins.

In addition, the geographic concentration of our properties in the Gulf Coast region means that some or all of the properties could be affected should the region experience:

severe weather, such as hurricanes and other adverse weather conditions;

delays or decreases in production, the availability of equipment, facilities or services;

delays or decreases in the availability of capacity to transport, gather or process production; and/or

changes in the regulatory environment.

For example, our oil and gas properties were damaged, prior to our acquisition of those properties, by both Hurricanes Katrina and Rita, and, since our acquisition of the properties, by Hurricanes Gustav, Ike and Isaac. This damage required us, and the prior owners, to spend time and capital on inspections, repairs and debris removal. In accordance with industry practice, we maintain insurance against some, but not all, of these risks and losses. For additional information, please read Our insurance may not protect us against all of the operating risks to which our business is exposed.

Because all or a number of the properties could experience many of the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

Oil and natural gas prices are volatile, and a substantial or extended decline in oil and natural gas prices would adversely affect our financial results and impede our growth.

Our financial condition, revenues, profitability and carrying value of our properties depend upon the prevailing prices and demand for oil and natural gas. Commodity prices also affect our cash flow available for capital expenditures and our ability to access funds through the capital markets. The markets for these commodities are volatile and even relatively modest drops in prices can affect our financial results and impede our growth.

Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

domestic and foreign supplies of oil and natural gas;

price and quantity of foreign imports of oil and natural gas;

actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil and natural gas price and production controls;

level of consumer product demand, including as a result of competition from alternative energy sources;

level of global oil and natural gas inventories;

political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;

weather conditions;

technological advances affecting oil and natural gas production and consumption;

overall U.S. and global economic conditions; and price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Lower oil and natural gas prices may not only decrease our expected future revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in us having to make downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

During the second half of 2014 and continuing into 2015, commodity prices, particularly oil prices, dropped sharply attributable to a number of factors, including growing supplies attributable to U.S. shale and other development and foreign supplies coming on line in the face of a projected slowing global economy and expected lower demand. As a result, we have seen our average price realized from the sale of oil decline from $97.45 per barrel of crude oil in December 2013 to $58.26 per barrel in December 2014. The sharp decline in prices has resulted in lower sales revenues and operating cash flow and downward adjustments to our estimated reserves and has resulted in the curtailment of numerous planned operations as well as the implementation of severe cost cutting measures. If prices do not recover sufficiently, or quickly enough, we may be unable to generate sufficient revenues to operate profitably and to meet our financial obligations.

Our actual recovery of reserves may differ from our proved reserve estimates.

This Form 10-K contains estimates of our proved oil and gas reserves. Estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing such estimates, projection of production rates, timing of development expenditures and available geological, geophysical, production and engineering data are analyzed. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. If our interpretations or assumptions used in arriving at our reserve estimates prove to be inaccurate, the amount of oil and gas that will ultimately be recovered may differ materially from the estimated quantities and net present value of reserves owned by us. Any inaccuracies in these interpretations or assumptions could also materially affect the estimated quantities of reserves shown in the reserve reports summarized in this Form 10-K. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, decommissioning liabilities and quantities of recoverable oil and gas reserves most likely will vary from estimates. 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.

We may be limited in our ability to maintain or book additional proved undeveloped reserves under the SEC s rules.

We have included in this Form 10-K certain estimates of our proved reserves as of December 31, 2014 prepared in a manner consistent with our and our independent petroleum consultant s interpretation of the SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies. Included within these SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped. During 2014 and 2013, we reclassified 7,755 MBoe and 2,439 MBoe, respectively, of reserves previously classified as proved undeveloped reserves as a result of the failure to develop those reserves within five years of their being recorded as proved undeveloped. We may incur similar reclassifications and charges in the future if we are unable to develop some or all of our proved undeveloped reserves within five years of booking.

As of December 31, 2014, approximately 63% of our total proved reserves were undeveloped and approximately 18% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, there can be no assurance that we will have the resources to fully develop those reserves or that all of those reserves will ultimately be developed or produced. While we presently act as operator on substantially all of our properties, to the extent that we are not the operator with respect to our proved undeveloped reserves, we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

Unless we replace crude oil and natural gas reserves, our future reserves and production will decline.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. As a result of declining cash flow from operations during 2013 and 2014, we have limited ability to fund exploration and development activities in the absence of outside funding. At December 31, 2014, we lacked a revolving credit facility and had limited funds on hand to support our drilling and development budget. In the absence of additional external financing, our ability to make planned capital investments to maintain and expand our reserves is limited and would be further impaired to the extent cash flow from operations is reduced due to natural declines in production, declines in commodity prices or otherwise. Even if we have sufficient financing to support our optimum development plan, we may not be successful in exploring for, developing or acquiring additional reserves.

The nature and age of our wells may result in fluctuations in our production resulting from mechanical failures and other factors.

The majority of our wells have been in operation and have produced for many years. As a result of the age of those wells and their location in bay environments, those wells typically experience higher maintenance requirements than newer wells and wells located onshore. As a result, some of our wells may periodically be shut-in to perform maintenance or to restore optimal production levels or as a result of maintenance by third parties that operate facilities that serve our wells. Due to the periodic need to shut-in wells, we experience routine fluctuations in production levels with production declining below normal operating capacity during periods of maintenance. During 2014, deferred maintenance and needed facilities modernizations associated with aging facilities contributed to a marked decline in production early in the year and required substantial investments and devotion of resources to address the same over the course of the year. Further, because of their location in a bay environment, we sometimes experience delays in identifying and addressing production declines.

Our offshore operations involve special risks that could affect our operations adversely.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. In particular, we are not intending to put in place business interruption insurance due to its high cost. We therefore may not be able to rely on insurance coverage in the event of such natural phenomena.

Our participation in, and realization of value from, shallow water ultra-deep shelf wells is subject to certain financing and operating risks that may prevent us from realizing the value of our deep reserve potential and expose us to delays, unexpected costs and other adverse financial consequences.

We have identified potential ultra-deep prospects underlying our transition zone acreage. The cost of exploration of such prospects, even when limited to our proportionate interest in such costs, is likely beyond that which we could fund from our current financial resources. Accordingly, we intend to seek partners to absorb a substantial portion of our share of such exploration costs. To that end, we have conducted discussions with various parties with respect to the potential formation of a joint venture to explore one or more ultra-deep prospects. We have not, as of December 31, 2014, entered into a definitive agreement with any prospective partner to fund or participate in the exploration of our ultra-deep prospects and, in light of the weak commodity price environment at December 31, 2014, we do not anticipate finalizing any such arrangements until a recovery in commodity prices has occurred. In the event that we enter into such a joint venture arrangement but are unable to make satisfactory arrangements to fund our portion of exploration costs, our interests in some of our ultra-deep prospects may be substantially reduced or lost with little or no benefit from such interests accruing to our benefit. Further, the shallow water ultra-deep wells are subject to very high pressures and temperatures. The drilling, logging and completion techniques associated with such wells may near the limits of existing technologies. As a result, new technologies and techniques are being developed to deal with these challenges. The use of advanced drilling technologies involves a higher risk of technological failure and potentially higher costs. In addition, there can be delays in completion due to necessary equipment that is specially ordered to handle the challenges of ultra-deep wells. Even if we are able to participate in drilling ultra-deep wells there is no assurance that such wells will be commercially viable. Such wells are presently expected to be natural gas wells and, based on the current low price of natural gas, there is no assurance that the wells can be operated in an economically feasible manner even if successfully completed.

Our participation in, and realization of value from, Gulf of Mexico shelf prospects is subject to participation of partners in the financing and development of those prospects and subjects us to risk associated with operating under rules of the U.S. Bureau of Ocean Energy Management (BOEM).

During 2013, we acquired four leases totaling 19,814 acres in the shallow Gulf of Mexico outer continental shelf (OCS). The leases are located in the federal waters of the Gulf of Mexico and are subject to rules and regulations of the BOEM. We have no history of developing and operating properties subject to BOEM regulation or in the deeper waters that characterize those leases and lack the financial resources to develop those prospects. Accordingly, we intend to seek partners in the development of such prospects which may entail farm-outs, promoted deals or other similar arrangements with partners having greater experience and financial resources to carry out such development and operating activities. If we are unable to secure partners to participate in such activities we may realize no value from the prospects and may lose our investment in those prospects. Even if we are able to secure necessary partners to fund, develop and operate those prospects, there is no guaranty that such activities will result in commercially viable wells.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. As a result of the recent bankruptcy of ATP Oil and Gas, the BOEM has indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators and may increase the amount of financial assurance required with respect to these obligations. While we believe that we are currently exempt from the supplemental bonding requirements of the BOEM, the BOEM could increase bonding requirements associated with planned development of our OCS properties. The cost of these bonds or other surety could be substantial and there is no assurance that bonds or other surety could be obtained in all cases. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. The cost of compliance with these supplemental bonding requirements could materially and adversely affect our financial condition, cash flows and results of operations.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Due to market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance policies are economically unavailable or available only for reduced amounts of coverage. Consistent with industry practice, we are not fully insured against all risks, including high-cost business interruption insurance and drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. Due to a number of catastrophic events in recent years, including Hurricanes Ivan, Katrina, Rita, Gustav, Ike and Isaac and the April 2010 Deepwater Horizon incident, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry suffered damage from Hurricanes Ivan, Katrina, Rita, Gustav, Ike and Isaac. As a result, insurance costs for many operators in the Gulf Coast region have increased significantly from the costs that similarly situated participants in this industry have historically incurred. Insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major wind storm in the event that damages are incurred. If storm activity in the future is as severe, insurance underwriters may no longer insure assets in the Gulf Coast region against weather-related damage. In addition, we do not intend to put in place business interruption insurance due to its high cost. This insurance may not be economically available in the future, which could adversely impact business prospects in the Gulf Coast region and adversely impact our operations. If an accident or other event resulting in damage to our operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a vendor, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

Competition for oil and gas properties and prospects is intense and some of our competitors have larger financial, technical and personnel resources that could give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors are major or independent oil and gas companies that possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than ours. We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases may be acquired through a sealed bid process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. Further, our competitors may be able to expend greater resources on the existing and changing technologies that we believe will impact attaining success in the industry. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves.

This Form 10-K contains estimates of our future net cash flows from our proved reserves. We base the estimated discounted future net cash flows from our proved reserves on average prices for the preceding twelve-month period and costs in effect on the day of the estimate. However, actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

the volume, pricing and duration of our natural gas and oil hedging contracts;

supply of and demand for natural gas and oil;

actual prices we receive for natural gas and oil;

our actual operating costs in producing natural gas and oil;

the amount and timing of our capital expenditures and decommissioning costs;

the amount and timing of actual production; and

changes in governmental regulations and taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute exploration and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our organization. The cost of oil field services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

Market conditions or transportation impediments may hinder access to oil and gas markets, delay production or increase our costs.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay production. The availability of a ready market for oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In offshore operations, market access depends on the proximity of and our ability to tie into existing production platforms and, where those facilities are owned or operated by third parties, the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. Restrictions on our ability to sell our oil and natural gas may have several other adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production. In the event that we encounter restrictions in our ability to tie our production to a gathering system, we may face considerable delays from the initial discovery of a reservoir to the actual production of the oil and gas and realization of revenues. In some cases, our wells may be tied back to platforms owned by parties with no economic interests in these wells. There can be no assurance that owners of such platforms will continue to operate the platforms. If the owners cease to operate the platforms or their processing equipment, we may be required to shut in the associated wells, which could adversely affect our results of operations.

We may not be the operator on all of our properties and therefore are not in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we may not serve as operator of all planned wells. We currently operate over 99% of our proved reserves, but do not expect to operate any wells that may be drilled on ultra-deep prospects or the Gulf of Mexico shelf prospects acquired during 2013. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

the timing and amount of capital expenditures;

the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;

the operator s expertise and financial resources;

approval of other participants in drilling wells;

selection of technology; and

the rate of production of the reserves.

Each of these factors, and others, could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Declines in the credit markets and the availability of credit or declines in equity values of our vendors, customers and counterparties, as well as declines in cash flow resulting from declines in commodity prices, may result in a significant reduction in our vendors, customers and counterparties liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could reduce our cash flows.

We sell the majority of our production to a small number of customers.

Two customers accounted for approximately 87% of our total oil and natural gas revenues during the year ended December 31, 2014. Our inability to continue to sell our production to those customers, if not offset by sales with new or other existing customers, could have a material adverse effect on our business and operations.

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith is often referred to as decommissioning. Should decommissioning be required that is not presently anticipated or the decommissioning be accelerated, such as can happen after a hurricane, such costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on our financial position and results of operations. During 2012 and 2013, we incurred decommissioning costs in excess of our estimates and established reserve and we may incur costs in excess of our reserves in the future.

Lower oil and gas prices and other factors may result in impairments of our asset carrying values.

Under the successful efforts method of accounting, whenever circumstances indicate that an asset may be impaired, we are required to compare the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows are lower than the unamortized capitalized cost, an impairment charge is realized to reduce the capitalized cost to fair value. In computing future undiscounted cash flows of assets, we take into account estimates of future crude oil and natural gas prices as well as operating costs, anticipated production from proved reserves and other relevant data. Accordingly, a decline in oil and natural gas prices could cause a future write-down of capitalized costs and a non-cash impairment charge against future earnings.

Our success depends on dedicated and skillful management and staff, whose departure could disrupt our business operations.

Our success depends on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

Risks Related to Our Risk Management Activities

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our cash flows.

We enter into derivative contracts to reduce the impact of natural gas and oil price volatility on our cash flow from operations. Currently, we use a combination of natural gas and crude oil swap and physical arrangements to mitigate the volatility of future natural gas and oil prices received on our production.

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

a counterparty may not perform its obligations under the applicable derivative instrument;

production is less than expected;

there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and

the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

If we are unable to effectively manage the commodity price risk of our production if energy prices fall, we may not realize the anticipated cash flows from our assets.

During the third quarter of 2012, we instituted a hedging program in an effort to manage our commodity price risk. If we fail to effectively manage the commodity price risk of our production and energy prices fall, we may not be able to realize the cash flows from our assets that are currently anticipated even if we are successful in increasing the production and ultimate recovery of reserves. Compared to some other participants in the oil and gas industry, we are a relatively small company with modest resources. Moreover, our lack of a revolving credit facility may limit the scope and nature of commodity price risk management tools available to us. There is the possibility that we may be unable to find counterparties willing to enter into derivative arrangements with us or be required to either purchase relatively expensive put options, or commit to deliver future production, to manage the commodity price risk of our future production. To the extent that we commit to deliver future production, we may be forced to make cash deposits available to counterparties as they mark to market these financial hedges. Proposed changes in regulations affecting derivatives may further limit or raise the cost, or increase the credit support required to hedge. This funding requirement may limit the level of commodity price risk management that we are prudently able to complete. In addition, we are unlikely to hedge undeveloped reserves to the same extent that we hedge the anticipated production from proved developed reserves.

Risks Related to Our Acquisition Strategy

Our acquisitions may be stretching our existing resources.

We acquired our principal properties in 2008 and may make acquisitions in the future. Future transactions may prove to stretch our internal resources and infrastructure. As a result, we may need to invest in additional resources, which will increase our costs. Any further acquisitions we make over the short term would likely intensify these risks.

We may be unable to successfully integrate the operations of the properties we acquire.

Integration of the operations of the properties we acquire with our existing business is a complex, time-consuming and costly process. Failure to successfully integrate the acquired businesses and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of combining the acquired operations include, among other things:

operating a larger organization;

coordinating geographically disparate organizations, systems and facilities;

integrating corporate, technological and administrative functions;

diverting management s attention from other business concerns;

diverting financial resources away from existing operations;

an increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

In addition, we face the risk of identifying, competing for and pursuing other acquisitions, which takes time and expense and diverts management s attention from other activities.

We may not realize all of the anticipated benefits from our acquisitions.

We may not realize all of the anticipated benefits from our future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

Our business strategy includes acquisitions, which may include acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. The successful acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

acceptable prices for available properties;

amounts of recoverable reserves;

estimates of future oil and natural gas prices;

estimates of future exploratory, development and operating costs;

estimates of the costs and timing of plugging and abandonment; and estimates of potential environmental and other liabilities.

Our assessment of acquired properties will not reveal all existing or potential problems nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we may not physically inspect every well, platform or pipeline. Even if we physically inspect each of these, our inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities associated with such risks. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. If an acquired property does not perform as originally estimated, we may have an impairment, which could have a material adverse effect on or financial position and results of operations.

Risks Related to Our Indebtedness and Access to Capital and Financing

Our level of indebtedness may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities.

As of December 31, 2014, we had total indebtedness of $179.8 million. Our leverage and the current and future restrictions contained in the agreements governing our indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Our indebtedness and other financial obligations and restrictions could have financial consequences. For example, they could:

impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general business activities or other purposes;

increase our vulnerability to general adverse economic and industry conditions;

result in higher interest expense in the event of increases in interest rates to the extent that our debt is at a variable rates of interest;

have a material adverse effect if we fail to comply with financial and restrictive covenants in any of our debt agreements, including an event of default if such event is not cured or waived;

require us to dedicate a substantial portion of future cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate requirements;

limit our flexibility in planning for, or reacting to, changes in our business and industry; and

place us at a competitive disadvantage to those who have proportionately less debt.

If we are unable to meet future debt service obligations and other financial obligations, we could be forced to restructure or refinance our indebtedness and other financial transactions, seek additional equity or sell assets. We may then be unable to obtain such financing or capital or sell assets on satisfactory terms, if at all.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures and development and exploration efforts will depend on our ability to generate cash in the future. Our future operating performance and financial results will be subject, in part, to factors beyond our control, including interest rates and general economic, financial and business conditions. We cannot assure that our business will generate sufficient cash flow from operations or that future borrowings or other facilities will be available to us in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs.

If we are unable to generate sufficient cash flow to service our debt, we may be required to:

refinance all or a portion of our debt;

obtain additional financing;

sell some of our assets or operations;

reduce or delay capital expenditures, research and development efforts and acquisitions; or

revise or delay our strategic plans.

If we are required to take any of these actions, it could have a material adverse effect on our business, financial condition and results of operations. In addition, we cannot assure that we would be able to take any of these actions, that these actions would enable us to continue to satisfy our capital requirements or that these actions would be permitted under the terms of the our various debt instruments.

The covenants in the indenture governing our senior notes impose restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

The indentures governing our senior notes contain various covenants that limit our ability and the ability of our subsidiaries to, among other things:

incur dividend or other payment obligations;

incur indebtedness and issue preferred stock; or

sell or otherwise dispose of assets, including capital stock of subsidiaries.

If we breach any of these covenants, a default could occur. A default, if not waived, would entitle certain of our debt holders to declare all amounts borrowed under the breached indenture to become immediately due and payable, which could also cause the acceleration of obligations under certain other agreements and the termination of our credit facility. In the event of acceleration of our outstanding indebtedness, we cannot assure that we would be able to repay our debt or obtain new financing to refinance our debt. Even if new financing was made available to us, it may not be on terms acceptable to us.

In early 2015, we entered into short term forbearance agreements with the principal holders of our outstanding indebtedness. Pursuant to the forbearance agreements, we paid interest accrued and owing as of December 31, 2014 on our most senior debt but did not pay interest accrued and owing as of January 1, 2015 on other debt. Additionally, we agreed to provide information to our debt holders, to retain financial advisors acceptable to our debt holders and undertook additional obligations with a view to recapitalizing or restructuring our company. The forbearance agreements were entered into in light of the steep drop in commodity prices that resulted in reduced revenues and operating cash flows. If we are unable to substantially improve operating cash flows, secure additional funding or reach a longer term accommodation from our debt holders, we may be required to sell assets or take other measures to address upcoming payment obligations, which measures may include seeking protection in bankruptcy.

We expect to have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

We expect to make substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our capital requirements depend on numerous factors and we cannot predict accurately the timing and amount of our capital requirements. We have historically financed our capital expenditures through cash flow from operations and cash on hand, including cash received through multiple equity and debt offerings undertaken during 2011, 2012 and 2013. However, if our capital requirements vary materially from those provided for in our current projections, we may require additional financing to support future capital expenditures. At December 31, 2014, we lacked a revolving credit facility, had inadequate resources on hand to fully fund our planned development operations and had no existing commitments to provide financing to support future capital requirements. A decrease in expected revenues or an adverse change in market conditions could make obtaining this financing economically unattractive or impossible.

The cost of raising money in the debt and equity capital markets may increase substantially while the availability of funds from those markets may diminish significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets may increase as lenders and institutional investors could increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity at all or on terms similar to our current debt and, in some cases, cease to provide funding to borrowers.

An increase in our indebtedness, as well as the credit market and debt and equity capital market conditions discussed above could negatively impact our ability to secure, and remain in compliance with the financial covenants under, any revolving credit facility which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth as expected, we could be required to seek alternative financing, the terms of which may be less favorable to us, or not pursue growth opportunities.

Without additional capital resources, we may be forced to limit or defer our planned natural gas and oil exploration and development program and this will adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations. We may also be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result, we may lack the capital necessary to complete potential acquisitions, obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

Any future financial crisis may impact our business and financial condition. We may not be able to obtain funding in the capital markets on terms we find acceptable because of the decline in commodity prices.

The recent turmoil in energy markets reflected in a steep drop in oil prices has had an impact on our business and our financial condition, and we may face challenges if market conditions do not improve or deteriorate in the future. Historically, we have used our cash flow from operations and funds provided by debt and equity offerings to fund our capital expenditures. The drop in commodity prices has decreased cash flow from operations to fund capital expenditures and debt service.

The drop in energy prices has also made it more difficult to obtain funding in the public and private capital markets. In particular, the cost of raising money in the debt and equity capital markets increased substantially while the availability of funds from those markets generally diminished significantly.

Risks Related to Environmental and Other Regulations

Our operations are subject to environmental and other government laws and regulations that are costly and could potentially subject us to substantial liabilities.

Our oil and gas exploration, production, and related operations are subject to extensive rules and regulations promulgated by federal, state, and local agencies. Failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws.

All of the jurisdictions in which we operate generally require permits for drilling operations, drilling bonds, and reports concerning operations and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. The statutes and regulations of certain jurisdictions also limit the rate at which oil and gas can be produced from our properties.

Our sales of oil and natural gas liquids are not presently regulated and are made at market prices. The price we receive from the sale of those products is affected by the cost of transporting the products to market. FERC regulations establish an indexing system for transportation rates for oil pipelines, which, generally, index such rate to inflation, subject to certain conditions and limitations. We are not able to predict with any certainty what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

FERC has civil penalty authority to impose penalties for current violations. While our operations have not been regulated by FERC, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional entities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Our oil and gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

require the acquisition of a permit before drilling commences;

restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

impose substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in:

the imposition of administrative, civil and/or criminal penalties;

incurring investigatory or remedial obligations; and

the imposition of injunctive relief, which could limit or restrict our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to be in compliance in all material respects with all applicable environmental laws and regulations, we cannot assure shareholders that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability.

Under certain environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination, or if current or prior operations were conducted consistent with accepted standards of practice. Such liabilities can be significant, and if imposed could have a material adverse effect on our financial condition or results of operations.

We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Our sales of oil and natural gas, and any hedging activities related to such energy commodities, expose us to potential regulatory risks.

FERC holds statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas, and any hedging activities related to these energy commodities, we are required to observe the market-related regulations enforced by these agencies, which hold enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition or results of operations.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act (CAA). Among the EPA s rules regulating greenhouse gas emissions under the CAA, one requires a reduction in emissions of greenhouse gases from motor vehicles and another regulates emissions of greenhouse gases from certain large stationary sources. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries and certain onshore oil and natural gas production facilities.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and a number of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The adoption of financial reform legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), signed into law in 2010, requires the Commodities Futures Trading Commission (CFTC), the SEC and other regulators to promulgate rules and regulations relating to, among other things, the over-the-counter derivatives market. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set 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 or positions would be exempt from these position limits. The financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules will be phased in over time according to a specified schedule which is dependent on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, 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. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas liquids and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas liquids and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether.

The construction and operation of energy projects require numerous permits and approvals from governmental agencies. We may not be able to obtain all necessary permits and approvals, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate cash expenditures and may create a risk of expensive delays or loss of value if a project is unable to proceed as planned due to changing requirements or local opposition.

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

President Obama and members of Congress have, on multiple occasions, advocated and proposed legislation that, if enacted, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include (1) the repeal of the percentage depletion allowance for oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. Several bills have been introduced in Congress that would implement these proposals. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Our By-laws contain provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment.

Our by-laws contain provisions that could delay or prevent changes in our management or a change of control that a shareholder might consider favorable. For example, they may prevent a shareholder from receiving the benefit from any premium over the market price of our common shares offered by a bidder in a potential takeover. Even in the absence of a takeover attempt, these provisions may adversely affect the prevailing market price of our common shares if they are viewed as discouraging takeover attempts in the future. For example, provisions in our by-laws that could delay or prevent a change in management or change in control include:

the board is permitted to issue preferred shares and to fix the price, rights, preferences, privileges and restrictions of the preferred shares without any further vote or action by our shareholders;

shareholders have limited ability to remove directors; and

in order to nominate directors, shareholders must provide advance notice and furnish certain information with respect to the nominee and any other information as may be reasonably required by the Company.

These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common shares.

Item 1B.

Unresolved Staff Comments

Not applicable

Item 2.

Properties

A description of our properties is included in Item 1. Business.

Item 3.

Legal Proceedings

Saratoga Resources. v. Professional Oil and Gas Marketing and Henry Calongne

In February 2010, Saratoga filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group LLC and/or Harvest Oil & Gas, LLC. The complaint alleged breach of the Purchase and Sale Agreements with the former owners arising from the underpayment or nonpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest Companies and related claims for damages. Specifically, the complaint alleged that the underpayment or nonpayment of such royalties constituted a breach, by the former owners, of the representations and warranties that all royalty payments of the Harvest Companies had been paid in full as of the closing of Saratoga s purchase of the Harvest Companies. Saratoga subsequently amended its complaint to add to the breach of contract claims additional claims based on fraud arising from the willful and knowing concealment of the underpayment of royalties. In its amended complaint, Saratoga named Henry Calongne and Professional Oil & Gas Marketing as additional defendants based on substantially identical facts as alleged in the complaint against the former owners of the Harvest Companies. Mr. Calongne and Professional Oil & Gas Marketing served as the agent of the Harvest Companies in computing the applicable royalty payments. Saratoga asserted that Mr. Calongne and Professional Oil & Gas Marketing either negligently or knowingly colluded with the former owners with respect to the underpayment of royalties to the State of Louisiana. Saratoga was seeking monetary damages with the total principal claims against all defendants being $1.4 million. Professional Oil & Gas Marketing asserted counterclaims against Saratoga for $0.2 million for unpaid fees and reimbursable tax payments. During 2012, Saratoga concluded settlements with Barry Ray Salsbury, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer and received approximately $769,000 and the claims and counterclaims involving those defendants were dismissed. In 2012, the case with respect to the remaining defendants was removed to the U.S. District for the Southern District of Louisiana and the matters relating to Brian Carl Albrecht were converted to an arbitration proceeding (see below). During 2013, Henry Calongne and Professional Oil and Gas Marketing were granted partial summary judgment and awarded $126,280 of marketing fees with said amount being placed in escrow pending final resolution of Saratoga s claims against each. The claim against Mr. Calongne and Professional Oil and Gas Marketing went to trial in March 2014 and in February 2015 all remaining claims by and between Saratoga against Mr. Calongne and Professional Oil and Gas Marketing were dismissed and the amounts deposited in escrow to pay marketing fees were released to Professional Oil and Gas Marketing.

The Harvest Group, LLC, et al. v. Brian Carl Albrecht; Harvest Operating LLC v. The Harvest Group, LLC, et al.

As noted above, in February 2010, Saratoga filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group LLC and/or Harvest Oil & Gas, LLC. The complaint alleged breach of the Purchase and Sale Agreements with the former owners arising from the underpayment or nonpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest Companies and related claims for damages. The claims against all parties other than Brian Carl Albrecht were subsequently settled and the claim against Mr. Albrecht was converted to an arbitration proceeding.

Harvest Operating, LLC, a company controlled by Mr. Albrecht, brought a separate cause of action against The Harvest Group, LLC, Harvest Oil & Gas, LLC and Saratoga Resources, Inc. (the Saratoga Parties), which cause of action was consolidated with the arbitration proceedings noted above. Harvest Operating s cause of action asserted a claim for damages based on the alleged wrongful termination of rights to use a pipeline owned and operated by the Saratoga Parties and the loss in value of a property operated by Harvest Operating based on its inability to transport production from that property via the pipeline in question.

The consolidated arbitration proceeding was conducted before a single arbitrator and, in August 2014, the arbitrator issued an Award and Reasons ruling (1) in favor of Saratoga, as relates to the royalty claim, and awarding to Saratoga $355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim, and awarding to Harvest Operating $3,757,050.

Saratoga believes that the award based on the pipeline use claim is wholly unsupported by the facts or the law. In November 2014, Saratoga filed a motion with the arbitrator to reconsider and clarify the arbitration award. Separately, in November 2014, Saratoga filed a Motion for Clarification and Remittitur in the 19th District Court of East Baton Rouge Parish, Louisiana. Both the motion with the arbitrator and the Motion in the District Court seek to vacate the arbitrator s award relating to the pipeline claim on multiple grounds. In December 2014, the arbitrator agreed to hear arguments as to the authority and grounds for reconsidering the arbitration award and the arbitrator s decision in that matter is pending.

Also, in November 2014, Saratoga filed a separate cause of action against Brian Albrecht in the 24th District Court of Jefferson Parish, Louisiana. The cause of action alleges breach of contract on the part of Mr. Albrecht and seeks damages in an amount equal to those awarded in the above arbitration proceeding. Saratoga asserts that the Purchase and Sale Agreement under which Saratoga secured beneficial ownership of the pipeline that is subject of the arbitration proceeding and the claims of Harvest Operating was illusory in that, if the reasoning of the arbitration award were to stand, Saratoga would not have received the rights associated with beneficial ownership and control of the pipeline and that, by withholding from Saratoga the ordinary rights associated with ownership of the pipeline, Mr. Albrecht was in breach of the terms of the Purchase and Sale Agreement.

Each of the above described proceedings remains pending and the parties to each of the proceedings have submitted various motions regarding the same.

We may from time to time be a party to lawsuits incidental to our business. Except as noted above, as of December 31, 2014, we were not aware of any current, pending, or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

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 is traded on the NYSE MKT (NYSE) under the symbol SARA . The following table sets forth the range of high and low sale prices of our common stock for each quarter during the past two fiscal years.

		High	Low
Calendar Year 2014	Fourth Quarter	$ 1.08	$ 0.14
	Third Quarter	1.80	1.18
	Second Quarter	2.06	1.15
	First Quarter	1.55	0.98
Calendar Year 2013	Fourth Quarter	$ 2.67	$ 1.10
	Third Quarter	2.90	1.47
	Second Quarter	2.67	1.45
	First Quarter	3.72	2.60

At April 10, 2015, the closing price of our common stock on the NYSE MKT was $0.22.

As of April 10, 2015, there were approximately 1,479 record holders of our common stock.

We have not declared or paid any dividends on our common stock since our inception, and we do not anticipate declaring or paying any dividends on our common stock for the foreseeable future. We currently intend to retain any future earnings to finance future growth. Any future determination to pay dividends will be at the discretion of our board of directors and will depend on our financial condition, results of operations, capital requirements and other factors the board of directors considers relevant. In addition, our ability to declare and pay dividends is restricted by our governing statute, as well as the terms of our existing credit facilities.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2014 with respect to the shares of our common stock that may be issued under our existing equity compensation plans.

Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities effected in column (a))**
Equity compensation plans approved by security holders [(1)]	1,430,000	2.28	1,520,000
Equity compensation plans not approved by security holders [(2)]	222,500	0.31	-
Total	1,652,500	2.59	1,520,000

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(1)

Consists of 3,000,000 shares reserved for issuance under the Saratoga Resources, Inc. 2011 Omnibus Incentive Plan (the 2011 Plan).

(2)

Consists of non-plan stand-alone stock option grants to directors, employees and consultants. The options are exercisable on terms generally described in Note 11. Common Stock Stock-Based Compensation to our financial statements included herein.

Item 6.

Selected Financial Data

Not applicable.

Item 7.

Management s Discussion and Analysis of Financial Conditions and Results of Operations

Overview

We are an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of crude oil and natural gas properties. As of December 31, 2014, our properties consisted of approximately 51,500 acres under lease, comprised of our principal producing properties covering approximately 31,700 acres gross/net in the transitional coastline and protected in-bay environments on parish and state leases in south Louisiana and approximately 19,800 acres gross/net under federal leases in the shallow Gulf of Mexico shelf.

Our state and parish leases span 11 fields which are characterized by over 30 years of development drilling and production history, including Grand Bay field which has over 70 years of production history and over 258 MMBoe produced to date, yet remains virtually unexplored at depths greater than 15,000 feet. Substantially all of our state and parish leases are held by production (HBP) without near-term lease expirations. Most of those properties offer multiple stacked reservoir objectives with substantial behind pipe potential.

Our shallow Gulf of Mexico shelf properties were acquired during 2013. At December 31, 2014, our shallow Gulf of Mexico shelf properties did not include any producing wells and we were engaged in efforts to seek partners to participate in development of such properties. We continually seek to enhance our acreage position through leasing and evaluation of opportunistic acquisitions primarily within, but not limited to, the transition zone and in the shallow Gulf of Mexico.

As of December 31, 2014, our total proved reserves were10.2 MMBoe, consisting of 5.8 MMBbls of oil and 26.8 Bcf of natural gas, approximately 73% of which was attributable to state and parish properties. The PV-10 of our proved reserves at December 31, 2014 was $209.3 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $69.4 million. Additionally, we had probable reserves of 25.6 MMBoe, consisting of 10.3 MMBbls of oil and 92.0 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities. We operate over 99% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

During 2014, we produced 670.1 MBoe, of which approximately 76% was oil and all of which was attributable to our state and parish properties. As of December 31, 2014, our development opportunities included 61 proved behind pipe and shut-in opportunities in 44 wells in 6 fields, 36 proved undeveloped opportunities within 15 proposed wells in 5 fields. An additional 61 formerly proved undeveloped opportunities within 21 proposed wells in 3 fields were reclassified as probable P90 reserves as required by the SEC five year PUD rule. Additionally, at December 31, 2014, we had 37 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2014, we had 41 probable undeveloped opportunities within 24 wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 86 possible undeveloped opportunities within 33 proposed wells in 5 fields. During the year ended December 31, 2014, we successfully completed one development well, 6 recompletions and 9 workovers.

Recent Developments

The following significant events, among others, affected our operations and financial position during 2013 and 2014:

Commodity Price Declines

During the second half of 2014, accelerating in the fourth quarter and continuing into 2015, we have experienced a sharp decline in commodity prices, particularly crude oil pricing. Global supply and demand conditions, driven by increasing domestic shale production as well as certain foreign sources coming back on-line together with expected softening of demand associated with projected weakness in foreign economies, has resulted in a decline in the price we realized from crude oil sales from an average of $98.35 per barrel in January 2014 to $58.26 per barrel in December 2014.

Drilling, Development and Infrastructure Activities

During 2014 and 2013, we invested $12.9 million and $31.4 million, respectively, in our drilling and development program and infrastructure projects, summarized as follows:

Development Drilling. During 2014 and 2013, we drilled one and four development wells, respectively.

The Rocky well, in Breton Sound 32 Field, was spud and completed in July 2013. The well targeted an elongated ridge, offsetting the SL 1227 #21 and #22 wells in the 5,800 sand, which is the main producing reservoir in the Breton Sound 32 field. A seventy-degree pilot hole was drilled followed by a sidetrack with a 750 lateral completion. This well was our first horizontal well.

The Zeke well, in Breton Sound 32 Field, was spud and completed in August 2013. The well also targeted the same 5,800 sand as the Rocky well but in a separate structure to the south-east and was completed as a high angle (82 degrees) directional. The Zeke well also established a previously unbooked, uphole recompletion opportunity in the overlying 5,750 sand, which also produces within the field.

The MP47 SL 195QQ-25 Roux Toux well in Main Pass 47 Field, was spud and completed in February 2013. The well reached total depth of 8,453 feet MD/8,000 feet TVD and was successfully completed as a dual completion in the 13 and 17 sands.

The SL 195QQ-209 Buddy well, in Grand Bay Field, was spud in December 2012 and completed in January 2013. The well reached total depth of 6,820 feet MD/TVD and was successfully completed in the 3A sand.

The Rocky 3 well, in Breton Sound 32 Field, was spud and completed in May 2014. The well also targeted the 5,800 sand with a 750 lateral completion.

Recompletion and Workover Program. During 2014, we carried out 9 recompletions and 14 workovers. 6 of the recompletions and 9 of the workovers were successful. One workover was still in progress at year end.

During 2013, we carried out 22 recompletions and 10 workovers. 17 of the recompletions and 9 of the workovers were successful.

Infrastructure Program. During 2014 and 2013, we invested $2.9 million and $5.6 million, respectively, in infrastructure improvements and additions to support existing production and anticipated increases in production. 2014 infrastructure investments were focused on construction of a new flow line to serve Breton Sound 32 and modifications to facilities in Main Pass 46, Main Pass 52, Grand Bay, Breton Sound 32 and Breton Sound 51.

Production Optimization Initiatives

During 2014, we undertook an exhaustive review of field operations in order to address ongoing run time issues that adversely impacted production rates across our fields and resulted in a marked decline in production during the first two months of 2014. Substantial time was spent in the field evaluating personnel, facilities, gas lift availability and other potential causes of unexpected down time in numerous fields. As a result of such evaluation, we made extensive changes in our field operating personnel and in our Covington office personnel. We also undertook extensive repairs and maintenance projects to improve certain facilities in the field and invested in gas lift projects and salt water disposal wells. The majority of the personnel changes, facilities upgrades and other projects were completed in early March 2014 with additional personnel changes, facilities upgrades and projects continuing through year end. We continue to monitor the results of such changes and upgrades and potential future changes and upgrades to optimize production.

Prior to implementing the changes and upgrades in early March, run times had fallen to an estimated 54% on average during January and February 2014 from 75% during fiscal 2013. Following the changes and upgrades, run times for the balance of the year generally exceeded 75% and average daily production rose to 2,038 barrels of oil equivalent per day (BOEPD) over the last nine months of 2014 from 1,330 BOEPD in the quarter ended March 31, 2014 which was down from 1,800 BOEPD during the fourth quarter of 2013.

Operating Costs

While the production initiatives undertaken during the first half of 2014 resulted in marked growth in production during the balance of 2014, our lease operating expenses for the first nine months rose on a year-over-year basis due, largely, to increased contract labor costs and facilities maintenance and repair costs incurred as part of the production optimization initiative. Beginning in the fourth quarter of 2014 and continuing into 2015, our focus has shifted to decreasing lease operating expenses as well as general and administrative expense. Cost reduction measures have focused on bringing contract employees in-house, eliminating redundant positions, managing marine transportation, optimizing our chemical program, lowering communications costs and replacing/modifying our compressors. With continued weakness in commodity prices, additional cost cutting measures have been implemented in early 2015, including a determination to downsize our Houston office, curtail expenditures on certain longer term projects and tighten discretionary spending. Those cost cutting measures are targeted to reduced lease operating expenses and general and administrative expenses by $13.3 million (a 39% decrease), in the aggregate, during 2015 as compared to 2014.

Drilling and Development Plans.

We have an extensive inventory of drilling opportunities, including numerous proved behind pipe and proved undeveloped opportunities as well as a number of exploratory opportunities. In light of the sharp drop in commodity prices in late 2014 and early 2015, our near term development plans are focused on recompletions, workovers and conversion of PDNP opportunities supported by cash on hand and cash flow.

Development operations with respect to our proved undeveloped properties are expected to be curtailed for the foreseeable future given the low commodity price environment and our limited financial resources at December 31, 2014. If and when market conditions support such, and subject to our ability to support such efforts through internal resources or outside financing, we intend to resume our efforts to develop our inventory of proved undeveloped prospects. Initial results from the Breton Sound 32 Block reservoir simulation project are encouraging and we expect to be able to book additional reserves once the results of that study are analyzed.

Our previous efforts to secure partners to support exploration and development of our deep prospects in Grand Bay and in the shallow Gulf of Mexico shelf have been temporarily halted in light of the decline in commodity prices. If and when market conditions support such, we intend to resume our efforts to identify and secure partners for the development of these prospects.

We continually evaluate our holdings with a view to optimizing our drilling and development plans based on ongoing development efforts, new geological and operating data, identification or acquisition of new opportunities and other factors. Accordingly, our drilling and development plans are fluid and subject to continuous revision and may vary from the plans described herein.

Leasehold and Seismic Activity

Gulf of Mexico Shelf Acreage. In 2013, we bid on and were awarded four leases, with seismic maps included, totaling 19,814 acres in the Central Gulf of Mexico Lease Sale 227. The acreage is in the shallow Gulf of Mexico shelf in water depths of 13 to 77 feet. Two of the leases are in the Vermilion area and two of the leases are in the Ship Shoal area. Lease bonuses on the prospects totaled $880,000 and first year annual rentals total $138,698. Additionally, we paid a prospect fee of $450,000 to a third party consultant.

Louisiana State Leases. In September 2013, we acquired an additional 857.96 acres under two Louisiana state leases in Breton Sound 18, 19 and 32 fields. The leasehold acreage is contiguous with our existing lease holdings in Breton Sound 18 and 32 fields, is close to existing facilities and pipeline infrastructure and in water depths of less than 20 feet. The leases have a primary term of three years and are subject to a 21% royalty burden. Lease bonuses on the acreage totaled $225,620. Annual rentals on the leases total $94,755 during the primary term.

During the third quarter of 2013, our operating agreement covering 253 acres and a single well in Little Bay Field terminated when we determined to temporarily abandon operations, resulting in an impairment charge of $2.2 million. In November 2013, we acquired a new three year lease covering 212 acres in Little Bay Field, including the acreage and associated well and reserves lost during the third quarter of 2013. Lease bonuses on the acreage totaled $86,026. Annual rentals on the lease total $37,171 and the lease bears a 25% royalty.

Impairments and Reserve Reclassifications

During 2014, we reported an impairment charge in the amount of $107.8 million. The impairment charge reflects the reclassification of certain reserves out of the proved undeveloped category and into the probable category due to application of the SEC s five year rule accounting for approximately $95.3 million, or 88.4% of the impairment charge and the steep decline in commodity prices which resulted in the expected undiscounted future cash flows at a producing field level to be less than the unamortized capitalized cost of assets in our several of our fields.

As a result of the application of the SEC s so-called five year rule, we reclassified 7,755 MBoe of reserves out of the proved undeveloped category and into the probable category. The five year rule requires removal of reserves from presentation as proved reserves if not developed within five years of initially being booked in the proved undeveloped category.

Legal Proceedings

In August 2014, the arbitrator in our long-standing legal proceedings against Brian Albrecht, and the counterclaims against us asserted by Mr. Albrecht and Harvest Operating, issued an Award and Reasons ruling (1) in our favor, as relates to our royalty claim, and awarding to us $355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim of Harvest Operating, and awarding to Harvest Operating $3,757,050. As a result of such award, we recorded an arbitration award expense and an accrued liability of $3.4 million.

We believe that the award based on the pipeline use claim is wholly unsupported by the facts or the law. In November 2014, we filed a motion with the arbitrator to reconsider and clarify the arbitration award. Separately, in November 2014, we filed a Motion for Clarification and Remittitur in the 19th District Court of East Baton Rouge Parish, Louisiana. Both the motion with the arbitrator and the Motion in the District Court seek to vacate the arbitrator s award relating to the pipeline claim on multiple grounds. In December 2014, the arbitrator agreed to hear arguments as to the authority and grounds for reconsidering the arbitration award and the arbitrator s decision in that matter is pending.

Also, in November 2014, we filed a separate cause of action against Brian Albrecht in the 24th District Court of Jefferson Parish, Louisiana. The cause of action alleges breach of contract on the part of Mr. Albrecht and seeks damages in an amount equal to those awarded in the above arbitration proceeding. We have asserted that the Purchase and Sale Agreement under which we secured beneficial ownership of the pipeline that is subject of the arbitration proceeding and the claims of Harvest Operating was illusory in that, if the reasoning of the arbitration award were to stand, we would not have received the rights associated with beneficial ownership and control of the pipeline and that, by withholding the ordinary rights associated with ownership of the pipeline, Mr. Albrecht was in breach of the terms of the Purchase and Sale Agreement.

Sale of 10% Senior Secured Notes

On November 22, 2013, we, and our several wholly-owned subsidiaries (the Guarantors), completed the issuance and sale to two institutional accredited investors (the First Lien Lenders) of $54.6 million in aggregate principal amount of its 10.0% Senior Secured Notes due 2015 (the First Lien Notes).

The First Lien Notes were issued pursuant to Purchase Agreements (the Purchase Agreement), and under an Indenture (the First Lien Indenture), by and among the Company, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (the First Lien Trustee). The First Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed (the Guarantees) on a senior secured basis by the Guarantors and will rank equally in right of payment with our, and the Guarantors , existing and future senior indebtedness and senior in right of payment to Second Lien Notes (as defined below).

The purchase price for the First Lien Notes and Guarantees was 100% of their principal amount. We received net proceeds from the issuance and sale of the First Lien Notes of approximately $25.4 million, after commissions and estimated offering expenses, and the surrender for retirement by the First Lien Lenders of $27.3 million in face amount of 12½% Senior Secured Notes (the Second Lien Notes).

The First Lien Notes mature on December 31, 2015, and interest, accruing at 10% per annum, is payable on the First Lien Notes on March 31, June 30, September 30 and December 31 of each year, commencing December 31, 2013.

We have the option to redeem all or a portion of the First Lien Notes at any time at 100% of the principal amount to be redeemed plus accrued and unpaid interest. Upon the occurrence of a change of control, we are required to offer to purchase the First Lien Notes at a price equal to 101% of the aggregate principal amount of First Lien Notes repurchased plus accrued and unpaid interest. Further, upon the occurrence of certain asset sales, we are required to provide notice of the same and are required to offer to purchase a defined portion of the First Lien Notes at a price equal to 100% of the principal amount of First Lien Notes repurchased plus accrued and unpaid interest.

The First Lien Indenture restrict our ability and the ability of our restricted subsidiaries to: (i) transfer or sell assets; (ii) make loans or investments; (iii) pay dividends, redeem subordinated indebtedness or make other restricted payments; (iv) incur or guarantee additional indebtedness or issue disqualified capital stock; (v) create or incur certain liens; (vi) incur dividend or other payment restrictions affecting certain subsidiaries; (vii) consummate a merger, consolidation or sale of all or substantially all of our assets; (viii) enter into transactions with affiliates; and (ix) engage in business other than the oil and gas business. These covenants are subject to a number of important exceptions and qualifications.

The First Lien Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the First Lien Notes; (ii) default in payment when due at maturity, upon redemption or otherwise, of the principal of, or premium, if any, on the First Lien Notes; (iii) failure by us or any of our restricted subsidiaries to comply with certain covenants relating to merger, consolidation or sale of assets; (iv) failure by us or any of our restricted subsidiaries to comply for 60 days after notice with certain provisions under the First Lien Indenture; (v) default under any mortgage, indenture or similar instrument of indebtedness by us or any of our restricted subsidiaries, if the indebtedness aggregates $5 million or more, and that default: (a) is caused by a failure to pay principal of, or interest or premium, if any, on such indebtedness prior to the expiration of the grace period for such indebtedness or (b) results in the acceleration of such indebtedness prior to its stated maturity; (vi) failure by us or any of our restricted subsidiaries to pay final judgments aggregating in excess of $5 million, which judgments are not paid, discharged or stayed for a period of 60 days; (vii) any First Lien Note guarantee ceases to be in full force and effect, other than in accordance with the terms of the First Lien Indenture, or a guarantor of the First Lien Notes denies or disaffirms its obligations under its First Lien Note guarantee; (viii) any security document ceases to be in full force and effect in all material respects or ceases to give the collateral agent the rights, powers and privileges purported to be created therein with respect to any collateral having a fair market value in excess of $1 million or we or any of the Guarantors contest the effectiveness, validity or enforceability of any of the security documents; and (ix) certain events of bankruptcy or insolvency described in the Indenture with respect to our company or any of our significant subsidiaries. In the case of an Event of Default arising from certain events of bankruptcy or insolvency with respect to our company, certain restricted subsidiaries or certain groups of restricted subsidiaries, all outstanding First Lien Notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing, the Trustee or the holders of at least 25% in principal amount of the then outstanding First Lien Notes may declare all the First Lien Notes to be due and payable immediately.

In connection with the issuance and sale of the First Lien Notes, we, the First Lien Trustee and The Bank of New York Mellon Trust Company, N.A., in its capacity as trustee and collateral under the Second Lien Documents (as defined below)(the Second Lien Trustee) entered into an Intercreditor Agreement (the Intercreditor Agreement). Pursuant to the Intercreditor Agreement, parties agreed that the lien with respect to collateral securing the First Lien Indenture and related First Lien Notes and Guarantees (the First Lien Obligations) shall be senior in right, priority, operation, effect and all other respects to any lien with respect to collateral securing the obligations under that certain Indenture dated as of June 12, 2011, as supplemented or amended from time to time thereafter (the Second Lien Indenture), by and among our company, the Guarantors named therein and the Second Lien Trustee, and the related Second Lien Notes in the aggregate amount of $125.2 million (the Second Lien Obligations).

Forbearance Agreements

On January 30, 2015, we, along with our subsidiaries, Lobo Operating, Inc., Lobo Resources, Inc., Harvest Oil & Gas, LLC and The Harvest Group, LLC entered into a forbearance agreement (the First Lien Forbearance Agreement) with the holders of the First Lien Notes. Also on January 30, 2015, we entered into a forbearance agreement (the Second Lien Forbearance Agreement) with the holders (the Second Lien Lenders) of seventy-five percent (75%) or more in principal amount of the Second Lien Notes.

The First Lien Forbearance Agreement and the Second Lien Forbearance Agreement were entered into following (i) our failure to pay to the First Lien Lenders an interest installment in the amount of $1.3 million scheduled for payment on December 31, 2014, and constituting a default if not paid by January 30, 2015 (the Anticipated First Lien Default), and (ii) our failure to pay to the Second Lien Lenders an interest installment in the amount of $7.9 million scheduled for payment on January 1, 2015, and constituting a default if not paid by February 2, 2015 (the Anticipated Second Lien Default, and, together with the Anticipated First Lien Default, the Specified Defaults).

We received confirmation from the First Lien Lenders that they hold more than 75% of the principal amount of the outstanding Second Lien Notes and have each agreed, during the Forbearance Period (as defined below), not to provide any direction to the Second Lien Trustee or to take any steps to enforce any rights of the Second Lien Trustee or the holders of Second Lien Notes occasioned by our failure to make the January 1, 2015 interest payment.

Pursuant to the First Lien Forbearance Agreement, the First Lien Lenders agreed to forbear, until the earlier of March 16, 2015 or the occurrence of certain defaults defined in the First Lien Forbearance Agreement (the Forbearance Period), from exercising certain of their default-related rights and remedies with respect to the Specified Defaults in order to permit an opportunity to effectuate a restructuring/refinancing or implement operational improvements.

Under the terms of the First Lien Forbearance Agreement, among other things, we agreed to (i) pay, by February 2, 2015, the December 31, 2014 interest payment owing to the First Lien Lenders, with interest at the default rate, in the amount of $1,378,650; (ii) pay expenses incurred by the First Lien Lenders in connection with the Forbearance Agreement, including paying a retainer to counsel for the First Lien Lenders; (iii) retain, by March 2, 2015, a financial advisor acceptable to the First Lien Lenders on terms acceptable to the First Lien Lenders; (iv) deliver to the First Lien Lenders a 6-week operating budget in form and methodology acceptable to the First Lien Lenders and to abide by that budget within permitted variances; (v) deliver to the First Lien Lenders, not later than March 2, 2015, certain financial, operating and other information and, not later than March 15, 2015, a two year business plan and 2015 budget; and (vi) cause our officers, financial advisors, investment bankers and others to furnish information reasonably requested by the First Lien Lenders.

Any breach on our part of any covenant in the First Lien Forbearance Agreement, or the commencement of any bankruptcy, insolvency or creditor relief proceedings by or with respect to our company, will constitute an event of default under the First Lien Forbearance Agreement.

Pursuant to the Second Lien Forbearance Agreement, the Second Lien Lenders agreed to forbear, during the Forbearance Period, from exercising certain of their default-related rights and remedies with respect to the Specified Defaults in order to permit an opportunity to effectuate a restructuring/refinancing or implement operational improvements. The Second Lien Forbearance Agreement is substantially identical to the First Lien Forbearance Agreement except that the January 1, 2015 interest payment on the First Lien Notes is not required to be made.

On March 16, 2015, we entered into amendments to the First Lien Forbearance Agreement and the Second Lien Forbearance Agreement, extending the Forbearance Period to April 30, 2015.

Advisory Agreement

In March 2015, pursuant to the terms of the Forbearance Agreements, we entered into an engagement letter (the Engagement Letter) with Conway MacKenzie Management Services, LLC (CMS). Pursuant to the Engagement Letter, we appointed principals of CMS to the Interim Chief Financial Officer and Strategic Alternatives Officer positions. Those officers are engaged to assist us in connection with our efforts to restructure or repay the First Lien Notes and Second Lien Notes. We will pay CMS a fee of $50,000 per month for services of the Interim Chief Financial Officer and pay hourly fees for services of other CMS personnel.

Critical Accounting Policies

We prepare our consolidated financial statements in this report using accounting principles that are generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements. We must make judgments, estimates, and in certain circumstances, choices between acceptable GAAP alternatives as we apply these rules and requirements. The most critical estimate we make is the engineering estimate of proved oil and gas reserves. This estimate affects the application of the successful efforts method of accounting, the calculation of depreciation, depletion, and amortization of oil and gas properties and the estimate of the impairment of our oil and gas properties. It also affects the estimated lives used to determine asset retirement obligations. In addition, the estimates of proved oil and gas reserves are the basis for the related standardized measure of discounted future net cash flows.

Estimated Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to management of our operations and ultimately our economic success. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis of calculating the unit-of-production rates for depreciation, evaluating impairment and estimating the life of our producing oil and gas properties in our asset retirement obligations. Our proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. We also report probable reserves and possible reserves, each of which reflects a lower degree of certainty of realization than proved reserves.

Independent reserve engineers prepared the estimates of our oil and gas reserves presented in this report with respect to transition zone properties, and our internal technical team prepared the estimates of our oil and gas reserves presented in this report with respect to Gulf of Mexico properties, based on guidelines promulgated under GAAP and in accordance with the rules and regulations of the SEC. The evaluation of our reserves by the independent reserve engineers and by our internal technical team involves their rigorous examination of our technical evaluation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Reservoir engineers interpret these data to determine the nature of the reservoir and ultimately the quantity of proved, probable and possible oil and gas reserves attributable to a specific property. Our proved reserves in this report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be effected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir, or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relies on these estimates of oil and gas reserves using commodity prices and costs. Commodity prices are based on the average prices as measured on the first day of each of the last twelve calendar months. In our 2014 year-end reserve report, we used an average oil price of $96.30 per Bbl, and a natural gas price of $4.47 per Mcf which includes adjustments by property for energy content, quality, transportation fees, and regional price differentials. While we believe that future operating costs can be reasonably estimated, future prices are difficult to estimate since the market prices are influenced by events beyond our control. Future global economic and political events will most likely result in significant fluctuations in future oil and gas prices.

Revenue Recognition

We recognize oil and gas revenue from interests in producing wells as the oil and gas is sold. Revenue from the purchase, transportation, and sale of natural gas is recognized upon completion of the sale and when transported volumes are delivered. We recognize revenue related to gas balancing agreements based on the sales method. Our net imbalance position at December 31, 2014 was immaterial.

Derivative Instruments

We account for derivative activities by applying authoritative accounting and reporting guidance which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under the accounting guidance and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings.

Oil and Gas Operations

Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for the classification of reserves as proved, the associated leasehold costs are reclassified into proved properties.

Oil and gas exploration costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venture approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Oil and gas development costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and crude oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have a future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable and estimable.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Oil and Gas Revenue

Oil and gas revenue for the year ended 2014 decreased by 23.8% to $52.3 million from $68.7 million in 2013.

The following table discloses the oil and gas sales revenues, net oil and natural gas production volumes, and average sales prices for the years ended December 31, 2014 and 2013:

	2014	2013
Revenues		
Oil	$ 47,799,650	$ 63,431,840
Gas	4,526,066	5,264,215
Total oil and gas revenues	$ 52,325,716	$ 68,696,055
Production		
Oil (Bbls)	511,700	603,600
Gas (Mcf)	950,100	1,198,800
Total production (Boe)	670,050	803,400
Average sales price		
Oil (per Bbl)	$ 93.41	$ 105.09
Gas (per Mcf)	4.76	4.39
Total average sales price (per Boe)	$ 78.09	$ 85.51

Oil production was down 91.9 MBbl, or 15.2%, as compared to 2013. The decrease was primarily due to steep declines in run times and production rates during the first quarter of 2014, elevated declines rates in certain high production wells, increased water-cut in selected wells, gas lift gas shortages, mechanical issues and flow line capacity constraints, all of which were partially offset by the addition of production from recompletions, workovers and new drills during 2014 and the second half of 2013.

Production optimization initiatives and infrastructure improvements undertaken throughout 2014 addressed the principal causes of decreased run times, gas lift gas shortages, mechanical issues and flow line capacity constraints, raising run time and production rates to approximately 80% and 1904 Boepd during the fourth quarter of 2014 from 54% and 1330 Boepd during first quarter of 2014.

Natural gas production was down 248.7 MMcf, or 20.7%, as compared to 2013. The decrease in gas production was principally related to natural decline and depletion of several wells and the recompletion of a previous gas producer uphole to an oil zone, partially offset by gas-targeted recompletions.

The decrease in realized hydrocarbon prices reflects the steep drop in global oil prices during the second half of 2014. We continued to realize a premium pricing on both our crude oil and natural gas production.

Oil and Gas Hedging

For 2014, we recorded a gain on oil and gas hedging of $1.6 million compared to a loss on oil and gas hedging of $1.7 million in 2013.

Other Revenues

Other revenues during 2014 consist principally of production handling fees and an insurance settlement for a loss incurred in the prior year. Other revenues during 2013 consisted principally of production handling fees and a reversal of an over accrual relating to the settlement of the Plaquemines Parish ad valorem tax litigation.

Operating Expenses

Operating expenses increased by 173.8% to $173.8 million for 2014 from $63.7 million in 2013. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2014 and 2013:

	2014		2013	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 24,631,620	$ 36.76	$ 21,685,103	$ 26.99
Workover expense	4,537,031	6.77	2,475,541	3.08
Exploration expense	706,904	1.06	900,255	1.12
Loss on plugging and abandonment	-	-	701,241	0.88
Depreciation, depletion and amortization	17,853,499	26.64	17,269,349	21.49
Impairment expense	107,774,206	160.83	2,179,075	2.71
Accretion expense	1,793,865	2.68	2,552,381	3.18
Gain on revision of asset retirement obligations	(75,178)	(0.11)	(564,719)	(0.70)
General and administrative expenses	9,549,430	14.25	9,253,600	11.52
Severance taxes	3,649,814	5.45	7,274,808	9.05
Arbitration loss	3,400,000	5.07	-	-
	$ 173,821,191	$ 259.40	$ 63,726,634	$ 79.32

The changes in operating expenses were primarily attributable to the factors discussed below.

Lease Operating Expense

Lease operating expenses for 2014 increased 13.9% to $24.6 million from $21.7 million in 2013 and, on a per BOE basis increased 36.2% to $36.76 per BOE from $26.99 per BOE in 2013.

The increase in operating expenses during 2014 was primarily attributable to (i) increased contract construction labor costs incurred in Grand Bay, Breton Sound, and Main Pass 25 Fields; (ii) one-time contract construction labor and building repair and maintenance expenses for living quarters in Grand Bay Field; (iii) increased contract pumping costs in Breton Sound and Main Pass 25/46 Fields for services provided to replace reduced field personnel as part of first quarter 2014 initiative to increase operational efficiencies; (iv) increased surface equipment repair and maintenance expense in Breton Sound 32 and Grand Bay Fields; (v) increased equipment rental expense for Breton Sound 32 and Grand Bay Fields; (vi) increased platform/flow lines repair and maintenance expenses in Main Pass 25/46 and Breton Sound 51 Fields; and (vii) increased well maintenance expense in Breton Sound 32 Field, largely due to a one time flow line well maintenance charge in March of 2014, in addition to some increases in Grand Bay and Main Pass 25/46 Fields. An estimated $2.0 million of the increase in lease operating expense related to contract construction labor, equipment repairs and maintenance, and well maintenance charges that were associated with our production optimization initiatives. We will seek to reduce our reliance on, and cost of, contract operating personnel as we seek to internally hire high-quality personnel for our field operations. We expect those expenses will decrease and result in future lease operating expenses leveling off. The increases in contract construction labor, contract pumping gaugers, repair and maintenance expenses were partially offset by decreases in slickline operations, payroll/payroll burden, and regulatory compliance expenses.

Workover Expense

Workover expense for 2014 increased 83.3% to $4.5 million from $2.5 million in 2013. The increase in workover expense was attributable to an increase in the number of workovers completed in 2014.

Exploration Expense

Exploration expense for 2014 decreased 21.5% to $0.7 million from $0.9 million in 2013. The decrease in exploration expenses principally relates to the full field studies done on the Gulf of Mexico shelf acreage during 2013.

Loss on plugging and abandonment

Loss on plugging and abandonment decreased to $0 in 2014 from $0.7 million in 2013. The 2013 loss reflects plugging and abandonment costs in excess of estimated costs reflected in our asset retirement obligation liabilities.

Depreciation, Depletion and Amortization (DD&A)

Depreciation, depletion and amortization for 2014 increased 3.4% to $17.9 million from $17.3 million in 2013. The increase in DD&A was attributable to a reduced proved reserve base which was partially offset by lower production levels and lower capital expenditures. DD&A is computed on the units-of-production method separately on each individual property and includes the accrual of future plugging and abandonment costs.

Impairment expense

Impairment expense for 2014 increased 4,845.9% to $107.8 million from $2.2 million in 2013. Impairment expense during 2014 related primarily to the Grand Bay and Vermilion 16 fields and resulted primarily from the reclassification of 7,755 MBoe of reserves out of the proved undeveloped category and into the probable category under the application of the SEC s so-called five year rule . The five year rule requires the removal of reserves from presentation as proved reserves if not developed within five years of initially being booked into the proved undeveloped category. Also contributing to the impairment expense was the steep decline in commodity prices which resulted in in lower expected future cash flows at a producing field level. Impairment expense during 2013 related to the loss of a lease, and associated reserves, at our Little Bay Field.

Accretion expense

Accretion expense for 2014 decreased 29.7% to $1.8 million from $2.6 million in 2013. Accretion expense relates to our asset retirement obligations. The decrease in accretion expense was attributable to changes in the anticipated plugging dates and discount rates used in calculating the asset retirement obligation for certain fields.

Gain on revision of asset retirement obligations

Gain on revision of asset retirement obligations decreased to $0.1 in 2014 from $0.6 million in 2013. The gains are due primarily to downward revisions in the asset retirement obligations relating to two properties which exceeded the carrying amount of the property.

General and Administrative Expense

General and administrative expense for 2014 increased 3.2% to $9.5 million from $9.3 million in 2013. The increase in general and administrative expense was primarily attributable to increased consulting fees and legal and professional fees, partially offset by a decrease in non-cash stock compensation expense.

Severance Taxes

Severance taxes for 2014 decreased 49.8% to $3.6 million from $7.3 million in 2013. The decrease was primarily attributable to production declines and the horizontal well severance tax exemptions obtained for our Rocky, Zeke, and Rocky 3 wells and the deep well severance tax exemption obtained for our Mesa Verde well. Some of these exemptions resulted in refunds of severance taxes paid in prior periods which totaled $0.5 million.

Arbitration Loss

As a result of the arbitration award rendered during 2014, we recorded an arbitration award expense of $3.4 million during 2014.

Other Income (Expense), Net

Net other expenses for 2014, consisting of net interest expense, increased 13.1% to $24.3 million from $21.4 million in 2014. The increase in interest expense was attributable to our placement of $54.6 million in principal of the First Lien Notes in November 2013, partially offset by a simultaneous reduction of $27.3 million in principal of the Second Lien Notes.

Income Tax Provision (Benefit)

For 2014, we recorded an income tax provision of $0.2 million compared to $8.6 million in 2013. The 2013 income tax provision reflects recognition of a valuation allowance against deferred tax assets which primarily relate to our net operating loss carry-forwards.

Our effective tax rates for 2014 and 2013 were (0.1)% and (48.6)%, respectively. Our effective tax rates were different than our federal statutory tax rate due to state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Financial Condition

Liquidity and Capital Resources

Our principal requirements for capital are to fund our day-to-day operations and exploration, development and acquisition activities and to satisfy our contractual obligations, primarily for the repayment of debt.

During 2013 and 2014 we funded operations out of operating cash flow and cash on hand, which funds have been supplemented by our receipt of funds from our issuance of $27.3 million of First Lien Notes for cash in November 2013. During 2013 and 2014, we did not have access to available capital under a revolving credit agreement and do not at this time have a revolving credit facility.

We incurred a loss from operations of $119 million for the year ended December 31, 2014 and had a working capital deficit of $186 million at December 31, 2014. These conditions raise substantial doubt as to our ability to continue as a going concern. These financial statements do not include any adjustments that might be necessary if we are unable to continue as a going concern. To address these matters, we are seeking to restructure our debt or find alternative sources of financing. There can be no assurance that we will be successful in our efforts.

We developed, and beginning in 2011 commenced, a layered, multi-faceted development and maintenance program designed to achieve short-, mid- and long-term objectives. Short-term objectives are focused on restoration of shut-in and curtailed production through investments in infrastructure and deferred maintenance and recompletions, workovers and thru-tubing plugbacks each designed to increase or restore production volumes from wells producing below capacity and an inventory of proved developed nonproducing opportunities. Mid-term, following or in conjunction with execution of short-term opportunities, our focus is on the development of an inventory of proved undeveloped opportunities within our inventory of proved undeveloped wells targeting normally pressured oil and gas. Long-term, following or in conjunction with the execution of our short- and mid-term opportunities, our focus is on continuing development of our reserves and exploratory drilling of deep shelf opportunities. During 2013 and 2014, while continuing to advance short-term objectives associated with continual investment in our infrastructure, we focused on our mid-term objectives through drilling proved undeveloped opportunities.

As a result of reduced production volumes early in 2014, and resulting operating losses and declines in cash flows, together with sharply lower commodity prices, our liquidity position deteriorated substantially during 2014. We have implemented cost cutting measures and curtailed development of our proved undeveloped opportunities in favor of building our cash position to, among other things, support our scheduled payments of interest on outstanding debt. In January 2015, we entered into forbearance agreements with our lenders, paying only the interest on first lien indebtedness but not paying interest on second lien indebtedness. We are presently working with our lenders and with prospective financing sources to add liquidity and/or refinance our debt. Our cash on hand at December 31, 2014, together with operating cash flows, is expected to be adequate to support basic operations and maintenance but, absent increased commodity prices and/or production, is not expected to be adequate to support development activities or debt service obligations over the next twelve months. Further, should we be unable to have the recent arbitration award reversed and be required to pay such award, our existing cash reserves would be materially reduced. We are presently evaluating options for bringing in additional financing to support our liquidity needs and planned development program. We do not, however, presently have any commitments to provide financing and there is no assurance that any additional financing will be provided on acceptable terms or at all. Should we be unable to pay our scheduled interest payments or to reach acceptable accommodations with our lenders regarding such payments, we may be subject to legal actions instituted by our lenders which may include foreclosure of liens and possible loss of assets.

Cash, Cash Flows and Working Capital

We had a cash balance of $10.9 million and negative working capital of $185.7 million at December 31, 2014 as compared to a cash balance of $32.5 million and working capital of $20.4 million at December 31, 2013. The change in cash on hand and working capital is primarily attributable to the operating losses during 2014 and the reclassification of our First Lien Notes and Second Lien Notes from long-term to short-term.

Operations used $5.1 million during 2014 as compared to providing $7.6 million during 2013. The change in operating cash flows during 2014 was principally attributable to reduced profitability resulting from lower production volumes, lower commodity prices, increased operating costs, and changes in our operating assets and liabilities.

Investing activities used cash flows of $14.7 million during 2014 as compared to $31.0 million during 2013. The decrease in cash used in investing activities during 2014 was primarily attributable to a reduction in development drilling during 2014.

Financing activities used $1.8 million during 2014 as compared to providing $23.7 million during 2013. Cash flows used in financing activities during 2014 related to repayments of short-term notes payable. Cash flows provided by financing activities during the 2013 reflect the receipt of $25.3 million of net proceeds from our November 2013 sale of First Lien Notes, partially offset by repayments of short term notes.

Debt

At December 31, 2014, we had $178.8 million of indebtedness outstanding, consisting of $54.6 million in face amount of 10% First Lien Notes, less $0.2 million of debt discount, and $125.2 million in face amount of 12½% Senior Secured Notes due 2016 less $0.8 million of debt discount.

We had no letters of credit outstanding at December 31, 2014 that were not fully collateralized by cash.

10% First Lien Notes. In November 2013, we issued $54.6 million in aggregate principal amount of our 10.0% Senior Secured Notes due 2015 (the First Lien Notes).

The 10% First Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our, and the Guarantors , existing and future senior indebtedness and senior in right of payment to 12½% Second Lien Notes.

The 10% First Lien Notes mature on December 31, 2015, and interest, accruing at 10% per annum, is payable on the notes on March 31, June 30, September 30 and December 31 of each year, commencing December 31, 2013.

We have the option to redeem all or a portion of the 10% First Lien Notes at any time at 100% of the principal amount to be redeemed plus accrued and unpaid interest. Upon the occurrence of a change of control, we are required to offer to purchase the 10% First Lien Notes at a price equal to 101% of the aggregate principal amount of 10% First Lien Notes repurchased plus accrued and unpaid interest. Further, upon the occurrence of certain asset sales, we are required to provide notice of the same and are required to offer to purchase a defined portion of the 10% First Lien Notes at a price equal to 100% of the principal amount of 10% First Lien Notes repurchased plus accrued and unpaid interest.

In connection with the issuance and sale of the 10% First Lien Notes, we, the First Lien Trustee and Second Lien Trustee entered into an Intercreditor Agreement. Pursuant to the Intercreditor Agreement, the parties agreed that the lien with respect to collateral securing the First Lien Indenture and related First Lien Obligations shall be senior in right, priority, operation, effect and all other respects to any lien with respect to collateral securing the obligations under Second Lien Indenture, by and among our company, the Guarantors named therein and the Second Lien Trustee, and the related 12½% Second Lien Notes.

12½% Second Lien Notes. In July 2011, we issued $127.5 million of our 12½% Second Lien Notes and retired all obligations owing under our prior credit facilities and all outstanding letter of credit obligations. In December 2012, we issued an additional $25.0 million of our 12½% Second Lien Notes. In November 2013, we retired $27.3 million in face amount of our 12½% Second Lien Notes pursuant to the issuance of a like amount of 10% First Lien Notes described above.

The 12½% Second Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our and the Guarantors existing and future senior indebtedness, subject, however, to the Intercreditor Agreement pursuant to which the 10% First Lien Notes are senior in right, priority, operation and effect to the lien securing the 12½% Second Lien Notes. The 12½% Second Lien Notes mature on July 1, 2016, and interest is payable on the notes on January 1 and July 1 of each year. We have the option to redeem all or a portion of the 12½% Second Lien Notes at any time on or after January 1, 2014 at the redemption prices specified in the Second Lien Indenture pursuant to which the 12½% Second Lien Notes were issued plus accrued and unpaid interest.

In January 2015, we entered into forbearance agreements with respect to both the First Lien Notes and the Second Lien Notes and were in default under those notes, including being default on the payment of interest owing as of January 1, 2015 with respect to the Second Lien Notes in the amount of $7.8 million.

In March 2015, we entered into amendments to the forbearance agreements which extended the forbearance period to April 30, 2015.

Capital Expenditures

Our capital spending for 2014 was $17.4 million relating primarily to development of our oil and gas properties, including drilling one development well ($5.7 million), 9 recompletions ($4.2 million), 14 workovers ($4.5 million), investments in multiple infrastructure projects ($2.9 million) and other leasehold costs ($0.1 million). Capital expenditures were down from $33.9 million during 2013.

As noted, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations. Actual levels of capital expenditures in any year may vary significantly due to many factors, including the extent to which properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services.

Contractual Obligations

The following table details our long-term debt and contractual obligations as of December 31, 2014:

Payments due by period

	Total	2015	2016 2017	2018 2019	Thereafter
Debt [1]	$ 188,990,000	$ 188,990,000	$ -	$ -	$ -
Operating leases	432,667	168,167	264,500	-	-
Capital leases	-	-	-	-	-
Asset retirement obligations	56,239,500	-	5,695,000	348,000	50,196,500
Total	$ 245,662,167	$ 189,158,167	$ 5,960,000	$ 348,000	$ 50,196,500

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(1)

Debt consists of amounts owing under our 10% First Lien Notes and 12½% Second Lien Notes and related unpaid interest. Debt shown as due in 2015 includes $127.5 million in principal amount of 12½% Second Lien Notes with a stated maturity date of July 1, 2016, which notes are subject to an ongoing forbearance agreement and, as such, are shown as due in 2015.

Risk Management Activities   Commodity Derivative Instruments

During the third quarter of 2012, we reinstituted a hedging program and have since utilized various derivative instruments to manage our risk associated with commodity price movements. We periodically enter into price-risk management transactions (e.g., swaps, and floors) for a portion of our oil and natural gas production. In certain cases, this allows us to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. The commodity derivative instruments apply to only a portion of our production, and provide only partial price protection against declines in oil and natural gas prices, and partially limit our potential gains from future increases in prices. None of these instruments have been used for trading purposes. During 2014, we did not record any significant unrealized gain on commodity derivatives in current earnings or accumulated other comprehensive income (loss).

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2014.

Inflation

We believe that inflation has not had a significant impact on our operations since inception.

Item 7A.

Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market-risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Prices have fluctuated significantly during the last five years and such volatility is expected to continue, and the range of such price movement is not predictable with any degree of certainty. In the normal course of business we periodically enter into commodity derivative transactions, including fixed price and ratio swaps to mitigate exposure to commodity price movements, but not for trading or speculative purposes.

As of December 31, 2014, we had the following crude oil hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Strike Price	Premium	Total Bbls
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	45,500
						45,500

We are exposed to market risk on derivative instruments to the extent of changes in market prices of crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. The change in the fair value of our commodity derivative contracts that are effective are recorded to Accumulated Other Comprehensive Income (Loss) in Stockholders Equity in the Consolidated Balance Sheet. The ineffective portion of the change in fair market value of derivatives is recorded currently in earnings as a component of Oil and Gas Hedging in the Consolidated Statements of Operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. For 2014, we did not record any unrealized gain or loss on commodity derivatives in accumulated other comprehensive income (loss).

Koch Supply & Trading, LP is the counterparty to our present covered call option. We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparty over the term of the commodity derivatives positions.

Interest Rate Risk

We consider our interest rate risk exposure to be minimal as a result of fixing interest rates on our existing debt. In the event that we put in place a new revolving credit facility, we anticipate that borrowings under such a facility will bear interest at a floating rate in which case we would be exposed to risk associated with such fluctuation.

Item 8.

Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See Index to Financial Statements on page 68 of this report.

Item 9.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A.

Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation as of December 31, 2014 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as that term is defined in Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with generally accepted accounting principles (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk. In addition, 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 order to evaluate the effectiveness of our internal control over financial reporting as of December 31, 2014, as required by Section 404 of the Sarbanes-Oxley Act of 2002, our management conducted an assessment, including testing, based on the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). A material weakness is a control deficiency, or a combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements will not be prevented or detected. As a result of our management s assessment it was determined that a material weakness existed in the system of Internal Controls over Financial Reporting relating to the calculation of asset retirement obligation (ARO) and that our internal controls over financial reporting were not effective at December 31, 2014. In order to remediate the material weakness, management will begin utilizing specialized software designed specifically to calculate ARO. This software is in the process of being implemented and used for the calculation of the Asset Retirement Obligation and is expected to be in place during 2015.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit smaller reporting companies to provide only management s report in this annual report.

Changes in Internal Control over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) occurred during the fourth quarter of fiscal 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B.

Other Information

Not applicable

PART III

Item 10.

Directors, Executive Officers and Corporate Governance

Executive Officers and Directors

Our current executive officers and Directors, and their ages and positions, are as follows:

Name	Age	Position
Thomas F. Cooke	66	Chief Executive Officer and Chairman
Andrew C. Clifford	60	President and Director
Randal B. McDonald, Jr.	57	Vice President Finance and Accounting
John W. Rhea, IV	62	Director
Rex H. White, Jr.	82	Director
Kevin M. Smith	70	Director

The following is a biographical summary of the business experience of our executive officers and Directors:

Thomas F. Cooke co-founded our company in 1990 and has served as our Chief Executive Officer and Chairman since October 2007. Mr. Cooke served as our President, Chief Executive Officer and Chairman from 1996 to 2007. In addition, Mr. Cooke has been self-employed as an independent oil and gas producer and investor for more than 30 years.

Andrew C. Clifford has served as our President and a Director since October 2007. He is a petroleum geologist/geophysicist with over 30 years of experience. Mr. Clifford s experience includes providing professional geological services on prospects throughout the United States and around the world as an independent consultant, as Vice President of Exploration for BHP Petroleum and as a Senior Geophysicist for BHP Petroleum, Kuwait Foreign Petroleum and Esso Exploration. Prior to joining the company, Mr. Clifford was a co-founder and Executive Vice President of Aurora Gas, LLC, an independent gas developer and producer with gas production operations in Cook Inlet, Alaska. Mr. Clifford holds a B.Sc, with honors, in Geology with Geophysics from London University and is a frequent speaker and published author on a variety of energy industry topics.

Randal McDonald, Jr. has served as our Vice President Finance and Accounting since January 2015 and previously served as our Controller since November 2011. Previously, from 2007 to 2011, Mr. McDonald served as Controller of Baseline Oil & Gas Corp., an independent oil and gas company. From 1998 until 2007, Mr. McDonald served as Chief Financial Officer and a Director of VTEX Energy, Inc., a publicly traded independent oil and gas company. Mr. McDonald holds a B.B.A. degree in Accounting from the University of Texas at Austin and is a licensed Certified Public Accountant.

John W. Rhea, IV has served as a Director since 2011. Since 2009, Mr. Rhea has been the owner and principal of J.W. Rhea & Associates, a petroleum exploration consulting firm. Mr. Rhea holds a B.S.M.E. in Engineering from the University of Texas.

Rex H. White, Jr. has served as a Director since 2006. Mr. White is the owner and principal of Rex H. White, Jr., Attorney at Law, a Board Certified Oil, Gas and Mineral Law attorney. Previously, Mr. White worked as a petroleum geologist/geophysicist for approximately ten years. Mr. White holds a B.S. in Geology, an M.A. in Geology with a minor in Petroleum Engineering and an L.L.B. all from the University of Texas.

Kevin M. Smith has served as a Director since 1997. Since 1984, Mr. Smith has been the owner and principal of Kevin M. Smith, Inc., a geophysical consulting firm. Mr. Smith holds a B.S. in Geology and Geophysics from the University of Houston.

There are no family relationships among the executive officers and directors. Except as otherwise provided in employment agreements, each of the executive officers serves at the discretion of the Board.

Involvement in Certain Legal Proceedings

Messrs. Cooke, Clifford, Smith and White were each directors of our company, and Messrs. Cooke and Clifford were officers of our company, at the time of our filing for protection under Chapter 11 of the U.S. Bankruptcy Code in March 2009. We exited bankruptcy with our assets and equity intact in May 2010.

Mr. Rhea served as a Director, and in various executive positions including Chief Executive Officer, Chief Operating Officer and President, of Latitude Solutions, Inc. from July 2012 to November 2012. Latitude Solutions filed for protection under Chapter 7 of the U.S. Bankruptcy Code in November 2012.

Board Committees

Our board has two standing committees: an audit committee and a compensation committee. The composition and other information relating to the functioning of those committees is summarized as follows:

Audit Committee

The audit committee is composed of three directors, Mr. Rhea, Chairman, and Messrs. White and Smith, each of whom meets the independence and financial literacy requirements as defined by applicable NYSE MKT and SEC rules. The audit committee assists the board in its general oversight of our financial reporting, internal controls, legal compliance, ethics programs and audit functions, and is directly responsible for the appointment, evaluation, retention and compensation of the registered public accounting firm. The board has determined that Mr. Rhea qualifies as an audit committee financial expert in accordance with the applicable rules and regulations of the SEC.

Compensation Committee

The compensation committee is composed of three directors, Mr. White, Chairman and Messrs. Rhea and Smith, each of whom is a non-employee independent director as defined by applicable NYSE MKT rules. The committee is responsible for establishing and administering the policies that govern both annual compensation and equity ownership. It reviews and approves salaries, bonus and incentive compensation, perquisites, equity compensation, and all other forms of compensation for our executive officers, including our chief executive officer. The compensation committee is also responsible for reviewing and administering our incentive compensation plans, equity incentive programs and other benefit plans. Pursuant to authority granted under our 2011 Omnibus Incentive Plan, the committee has delegated to Messrs. Cooke and Clifford the authority to make awards to employees other than those subject to Section 16 of the Securities Exchange Act of 1934. The committee may from time to time engage the services of an independent executive compensation consultant to advise the committee on matters related to executive compensation. The committee periodically reviews and makes recommendations to the board with respect to director compensation.

Compensation Committee Interlocks and Insider Participation

The current members of our compensation committee are Messrs. White, Rhea and Smith. In 2014, none of our executive officers served as a director or member of the compensation committee of another entity, where an executive officer of the entity served as one of our directors or on our compensation committee.

Code of Ethics

The Board of Directors has adopted a separate Code of Business Ethics for the CEO and Senior Financial Officers. This Code of Ethics supplements our general Code of Business Ethics and is intended to promote honest and ethical conduct, full and accurate reporting, and compliance with laws as well as other matters.

The Code of Business Ethics for the CEO and Senior Financial Officers was filed as an exhibit to the Annual Report on Form 10-KSB for the year ended December 31, 2005 and is available for review at the our web site at www.saratogaresources.net.

Compliance with Section 16(a) of Exchange Act

Under the securities laws of the United States, our directors, executive officers, and any person holding more than ten percent of our common stock are required to report their initial ownership of common stock and any subsequent changes in that ownership to the Securities and Exchange Commission. Specific due dates for these reports have been established and we are required to disclose any failure to file by these dates during fiscal year 2014. To our knowledge, all of the filing requirements were satisfied on a timely basis in fiscal year 2014. In making these disclosures, we have relied solely on copies of reports provided to us.

Item 11.

Executive Compensation

Summary Executive Compensation Table

The table below summarizes the total compensation paid to or earned by our named executive officers for each of the two years ended December 31, 2014.

Name and Principal Position	Year	Salary	Bonus	Stock Awards	Option Awards(1)	All Other Compensation(2)	Total
Thomas F. Cooke	2014	$ 317,200	$ -	$ -	$ -	$ 61,014	$ 378,214
Chairman of the Board and Chief Executive Officer	2013	311,100	-	-	252,500	45,927	609,527
Andrew C. Clifford	2014	317,200	-	-	-	64,908	382,108
President	2013	311,100	-	-	252,500	48,127	611,727
Randal McDonald	2014	160,000	-	-	23,700	6,400	190,100
VP Finance and Accounting	2013	160,000	-	-	-	8,208	168,208
John Ebert	2014	200,000	-	-	47,400	8,000	255,400
VP Finance and Business Development	2013	74,173	10,000	-	150,300	2,850	237,323

(1)

The amounts reported in the Option Awards column reflect the grant date fair value of the options granted to the named executive officers in the year reflected, determined using the Black-Scholes option model. For information relating to the assumptions made by us in valuing the option awards made to our named executive officers in fiscal year 2014, refer to Note 11 of our financial statements for the year ended December 31, 2014.

(2)

All other compensation consists of:

Name	**Year**	**Travel Pay**	**Unused Vacation Pay**	**Auto Allowance**	**401k Plan Contribution**
Thomas F. Cooke	2014	$ 44,400	$ -	$ 16,614	$ -
	2013	19,800	-	26,127	-
Andrew C. Clifford	2014	34,800	-	19,908	10,200
	2013	13,000	-	24,927	10,200
Randal McDonald	2014	-	-	-	6,400
	2013	-	1,285	-	6,923
John Ebert	2014	-	-	-	8,000
	2013	-	-	-	2,850

Employment Agreements

In June 2013, our board of directors approved new employment agreements for our two principal officers, Thomas Cooke and Andy Clifford. Pursuant to their employment agreements, (i) the annual base salary of Messrs. Cooke and Clifford was increased from its then current level of $305,000 by 4%, to $317,200, on July 1, 2013 and increases by 4% on July 1 of each succeeding year; (ii) the automobile allowance of Messrs. Cooke and Clifford was modified to either provide a company vehicle or pay a monthly automobile allowance, which allowance remains $700 per month for Mr. Clifford and was increased to $950 per month for Mr. Cooke; additionally, beyond repair and maintenance costs previously paid by the company, the automobile allowance has been revised to cover all costs of operating a vehicle; (iii) the expense reimbursement provisions were modified to clarify that the company will pay all incremental costs associated with maintenance of home offices by Messrs. Cooke and Clifford, including costs of internet service, telephone and facsimile service and, with respect to Mr. Clifford, a home workstation; (iv) travel pay in the amount of $200 per day was added for each overnight stay or out-of-town travel of twenty-four hours exclusively for business purposes; (v) Messrs. Cooke and Clifford each received options to purchase 250,000 shares of common stock exercisable at $3.00 per share for a term of five years and vesting on a quarterly basis over eight quarters; (vi) in the event of termination of employment due to death or disability, we will continue to pay base salary to the executive or his estate for a period of twelve months; and (vii) in the event of termination of employment by the company without cause or by the executive for good reason , we will pay a lump sum to the executive in an amount equal to two times the base salary and bonus paid during the twelve months immediately preceding termination and shall continue to provide health insurance for a period of twenty-four months.

Outstanding Equity Awards at December 31, 2014

The following table includes certain information with respect to unexercised options held by named executive officers at December 31, 2014:

		Option Awards			
Name	**Grant Date**	**Number of Securities Underlying Unexercised Options Exercisable**	**Number of Securities Underlying Unexercised Options Unexercisable**	**Option Exercise Price**	**Option Expiration Date**
Thomas Cooke	06/10/13	187,500	62,500(1)	$ 3.00	06/09/18
Andrew Clifford	06/10/13	187,500	62,500(1)	3.00	06/09/18
Randal McDonald	11/28/11	30,000		4.62	11/28/18
	05/13/14	10,000	20,000(2)	1.30	05/13/21

John Ebert	08/12/13	30,000	60,000(2)	1.72	08/12/20
	05/13/14	20,000	40,000(2)	1.30	05/13/21

(1)

The stock options vest and become exercisable ratably over eight quarters from the grant date. The stock options will become immediately exercisable in their entirety in the event of certain changes in control.

(2)

The stock options become exercisable in 1/3 increments six months from the grant date and on the first and second anniversaries of the grant date.

Director Compensation

We use a combination of cash and equity-based incentive compensation to attract and retain qualified candidates to serve on our board. In setting director compensation, we consider the significant amount of time directors dedicate in fulfilling their duties as directors as well as the skill-level required by the company to be an effective member of our board. The form and amount of director compensation is reviewed by our compensation committee, which makes recommendations to the full board.

Each non-employee director receives an annual fee of $10,000 and committee chairs receive an annual fee of $6,000 for the audit committee and $4,000 for all other committees, each of which fees is payable in two semi-annual installments. Each non-employee director is reimbursed for reasonable out-of-pocket expenses incurred in attending such meetings. Additionally, upon initial appoint or election as a director and annually upon reelection as a director, non-employee directors are granted stock options to purchase 35,000 shares of our common stock at the then fair market value. Under our present director compensation program, option grants expire on the seventh anniversary of the grant date and vest 50% on the date of grant and 50% on the first anniversary of the date of grant.

In January 2015, a special committee of independent directors was formed to consider strategic alternatives in connection with our entry into Forbearance Agreements with our lenders. Members of the special committee, consisting of Mr. Rhea, as chairman, and Messrs. White and Smith, are paid a monthly fee for service on the committee in the amount of $4,000 for the chairman and $2,000 for other members.

The table below summarizes the total compensation paid to or earned by our non-management directors during 2014. The amounts included in the Stock Awards and Option Awards columns reflect the aggregate grant date fair value, and do not necessarily equate to the income that will ultimately be realized by the director for these awards.

Name of Director	Fees Earned or Paid in Cash	Stock Awards	Option Awards(1)	All Other Compensation	Total
John W. Rhea, IV	$ 16,000	$ -	$ 34,650	$ -	$ 50,650
Kevin M. Smith	10,000	-	34,650	-	44,650
Rex H. White, Jr.	14,000	-	34,650	-	48,650

(1)

Amounts reflect the aggregate grant date fair value of the option awards (options). The Black-Scholes option model was used to determine the grant date fair value of the options that we granted to the directors. For information relating to the assumptions made by us in valuing the option awards made to our non-management directors in fiscal year 2014, refer to Note 11 of our financial statements for the year ended December 31, 2014.

As of December 31, 2014, each director had the following number of options outstanding: Mr. Rhea, 105,000; Mr. Smith, 190,000; and, Mr. White, 190,000.

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Unless otherwise indicated, the table below shows the amount of our common stock beneficially owned as of April 1, 2015, by (1) each person known to beneficially own more than 5% of our outstanding common stock, (2) each of our directors, nominees and executive officers listed in the Summary Compensation Table under Item 11 above (collectively, the named executive officers), and (3) all directors and executive officers as a group.

Name of Beneficial Owner	Number of Shares Not Subject to Options	Number of Shares Subject to Exercisable Warrants and Options (1)	Total Number of Shares Beneficially Owned (1)	Percent of Class (1)(2)
Thomas F. Cooke	6,142,422(3)	218,750	6,361,172	20.4%
GSO Capital Partners (4)	4,800,000		4,800,000	15.5%
Andrew C. Clifford	2,637,164(5)	218,750	2,855,914	9.2%
John W. Rhea, IV		105,000	105,000	*
Kevin M. Smith	195,473(6)	190,000	385,473	1.2%
Rex H. White, Jr.	52,500	190,000	242,500	*
Randal McDonald		40,000	40,000	*
John Ebert				
Directors and executive officers as a group (7 persons) (3)(5)(6)	9,027,559	962,500	9,990,059	31.3%

*

Ownership is less than 1%.

(1)

Reflects our common stock that could be acquired within sixty days of the record date upon the exercise of outstanding warrants and options.

(2)

Based on 30,986,601 shares of our common stock outstanding as of April 1, 2015.

(3)

Includes 104,148 shares held by Mr. Cooke s spouse, as to which he disclaims beneficial ownership.

63

(4)

Address is 345 Park Avenue, New York, NY 10154. Based on a Schedule 13G, Amendment No. 1, filed with the SEC on February 14, 2013. Blackstone/GSO Capital Solutions Fund L.P. and Blackstone/GSO Capital Solutions Overseas Master Fund L.P. (collectively, the GSO Funds) respectively hold 3,578,781 and 1,221,219 shares of our common stock. Blackstone/GSO Capital Solutions Associates LLC is the general partner of Blackstone/GSO Capital Solutions Fund LP. GSO Holdings I LLC is the managing member of Blackstone/GSO Capital Solutions Associates LLC. GSO Capital Partners LP is the investment manager of Blackstone/GSO Capital Solutions Overseas Master Fund L.P., and in that respect holds discretionary investment authority for, and may be deemed to be the beneficial owner of the shares held by, Blackstone/GSO Capital Solutions Overseas Master Fund L.P. GSO Advisor Holdings L.L.C. is the general partner of GSO Capital Partners LP. Blackstone Holdings I L.P. is the sole member of each of GSO Holdings I LLC and GSO Advisor Holdings L.L.C. Blackstone Holdings I/II GP Inc. is the general partner of Blackstone Holdings I L.P. The Blackstone Group L.P. is the controlling shareholder of Blackstone Holdings I/II GP Inc. Blackstone Group Management L.L.C. is the general partner of The Blackstone Group L.P. Stephen A. Schwarzman is the founding member of Blackstone Group Management L.L.C. In addition, each of Bennett J. Goodman, J. Albert Smith III and Douglas I. Ostrover, each of whom serves as an executive of GSO Holdings I LLC, which is an affiliate of Blackstone/GSO Capital Solutions Associates LLC, may have shared investment control with respect to the common stock held by the GSO Funds.

(5)

Includes (a) 2,500,000 shares held by held by CPK Resources, LLC of which Mr. Clifford is the principal officer and owner, (b) 5,886 shares held by Mr. Clifford s SEP-IRA, and (c) 4,173 shares held by the SEP-IRA of Mr. Clifford s spouse, as to which he disclaims beneficial ownership.

(6)

Includes 20,000 shares held by Mr. Smith s spouse, as to which he disclaims beneficial ownership.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

On November 22, 2013, we completed the sale of $54.6 million in aggregate principal amount of 10.0% Senior Secured Notes due 2015 (the First Lien Notes). The First Lien Notes were issued for $27.3 million in cash and surrender for retirement of $27.3 million in face amount of 12½% Senior Secured Notes (the Second Lien Notes). Further details regarding the terms of the First Lien Notes can be found in our Current Report on Form 8-K filed November 25, 2013.

Funds (the GSO Funds) managed by GSO Capital Partners purchased $36.4 million of the First Lien Notes, paying $18.2 million in cash and surrendering for cancellation $18.2 million in face amount of Second Lien Notes.

In January 2015, we entered into Forbearance Agreements (the Forbearance Agreements) with the GSO Funds relating to both their First Lien Notes and their Second Lien Notes. The Forbearance Agreements provided for forbearance, by the GSO Funds and other holders, until March 16, 2015 on exercise of certain rights under the notes and the establishment of certain reporting obligations on our part as well the payment of certain expenses and the undertaking to appointment a financial advisor acceptable to the holders of the notes. On March 16, 2015, we entered into an amendment to the Forbearance Agreements, extending the forbearance period to April 30, 2015, among other things. Further details regarding the Forbearance Agreements, and amendments thereto, can be found in our Current Reports on Form 8-K filed February 3, 2015 and March 20, 2015, respectively.

The GSO Funds hold, in the aggregate, 4.8 million shares, or 15.5%, of our outstanding common stock.

Item 14.

Principal Accounting Fees and Services

The following table summarizes the fees of MaloneBailey, LLP, our registered public accounting firm in 2014 and 2013, billed to us for each of the last two fiscal years:

Fee Category	FY 2014	FY 2013
Audit Fees (1)	$ 211,000	$ 259,865
Audit-Related Fees	-	-
Tax Fees	-	-
All Other Fees (2)	10,000	-
Total Fees	$ 221,000	$ 259,865

(1)

Audit fees consist of fees for the audit of our financial statements, the review of the interim financial statements included in our Quarterly Reports on Form 10-Q, and other professional services provided in connection with statutory and regulatory filings or engagements.

(2)

Other fees consist of amounts paid for comfort letters and services in connection with financing transactions and the filing of registration statements with the Securities and Exchange Commission.

The audit committee has adopted policies and procedures relating to the approval of all audit and non-audit services that are to be performed by our registered public accounting firm. This policy generally provides that we will not engage our registered public accounting firm to render audit or non-audit services unless the service is specifically approved in advance by the audit committee or the engagement is entered into pursuant to one of the pre-approval procedures described below.

From time to time, the audit committee may pre-approve specific types of services that are expected to be provided by our registered public accounting firm during the next 12 months. Any such pre-approval is detailed as to the particular services to be provided and is also generally subject to a maximum dollar amount.

The committee s practice is to consider for approval, at its regularly scheduled quarterly meetings, all audit and non-audit services proposed to be provided by our registered public accounting firm. In situations where a matter cannot wait until the next regularly scheduled committee meeting, the chairman of the committee has been delegated authority to consider and, if appropriate, approve audit and non-audit services or, if in the chairman s judgment it is considered appropriate, to call a special meeting of the committee for that purpose.

PART IV

Item 15.

Exhibits and Financial Statement Schedules

1.

Financial statements. See Index to Financial Statements on page 68 of this report.

2.

Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date Filed	Number	Filed Herewith
3.1	Restated Articles of Incorporation of Saratoga Resources with amendments, dated May 14, 2010	8-K	05/18/10	3.1	
3.2	Amended and Restated Bylaws of Saratoga Resources, dated May 16, 2011	8-K	05/20/11	3.1	
4.1	Indenture Agreement, dated July 12, 2011, by and among Saratoga Resources and The Bank of New York Mellon Trust Company, N.A., as trustee	8-K	07/15/11	4.1	
4.2	First Supplemental Indenture, dated December 4, 2012, by and among Saratoga Resources and The Bank of New York Mellon Trust Company, N.A., as trustee	8-K	12/05/12	4.1	
4.3	Indenture, dated November 22, 2013, by and among Saratoga Resources and The Bank of New York Mellon Trust Company, N.A., as trustee	8-K	11/25/13	4.1	
4.4	Intercreditor Agreement, dated November 22, 2013, by and among Saratoga Resources, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee on behalf of holders of First Lien Notes, and The Bank of New York Mellon Trust Company, N.A., as trustee on behalf of holders of Second Lien Notes	8-K	11/25/13	4.2	
4.5	Forbearance Agreement to First Lien Indenture, dated January 30, 2015	8-K	02/03/15	10.1	
4.6		8-K	02/03/15	10.2	

	Forbearance Agreement to Second Lien Indenture, dated January 30, 2015				
4.7	Second Amendment to Forbearance Agreement to First Lien Indenture, dated March 16, 2015	8-K	03/20/15	10.1	
4.8	Second Amendment to Forbearance Agreement to Second Lien Indenture, dated March 16, 2015	8-K	03/20/15	10.2	
4.9	Form of Registration Rights Agreement, dated November 22, 2013, by and among Saratoga Resources, the guarantors named therein and the purchasers of First Lien Notes	8-K	11/25/13	4.3	
10.1	Employment Agreement, dated June 10, 2013, with Thomas Cooke*	8-K	06/14/13	10.1	
10.2	Employment Agreement, dated June 10, 2013, with Andrew Clifford*	8-K	06/14/13	10.2	
10.3	Investor Rights Agreement, dated July 12, 2011	8-K	07/15/11	10.3	
10.4	Saratoga Resources, Inc. 2011 Omnibus Incentive Plan	S-8	09/13/11	10.1	
10.5	Form of $8.00 Warrant	8-K	05/25/12	10.2	
10.6	Saratoga Resources, Inc. Annual Incentive Plan*	8-K	03/23/12	10.1	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	01/25/06	14.1	
21.1	List of subsidiaries	10-K	04/14/10	21.1	
23.1	Consent of MaloneBailey, LLP				X
23.2	Consent of Collarini Associates				X
31.1	Section 302 Certification of CEO				X
32.2	Section 302 Certification of CFO				X
32.1	Section 906 Certification of CEO				X
32.2	Section 906 Certification of CFO				X
99.1	Reserve Report of Independent Engineer Collarini Associates				X

*

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.

SARATOGA RESOURCES, INC.

Dated:	April 15, 2015	By:	/s/ Thomas F. Cooke
			Chairman and Chief Executive Officer

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/ Thomas F. Cooke Thomas F. Cooke	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	April 15, 2015
/s/ Andrew C. Clifford Andrew C. Clifford	President and Director	April 15, 2015
/s/ Kevin Smith Kevin Smith	Director	April 15, 2015
/s/ Rex H. White, Jr. Rex H. White, Jr.	Director	April 15, 2015
/s/ John W. Rhea, IV John W. Rhea, IV	Director	April 15, 2015
/s/ Randal McDonald Randal McDonald	Vice President Finance and Accounting (Principal Accounting and Financial Officer)	April 15, 2015

SARATOGA RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Saratoga Resources, Inc.

Houston, Texas

We have audited the consolidated balance sheets of Saratoga Resources, Inc. and its subsidiaries (collectively, the Company) as of December 31, 2014 and 2013, and the related consolidated statements of operations and comprehensive income (loss), stockholders equity (deficit), and cash flows for the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Saratoga Resources, Inc. and its subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, The Company has suffered recurring losses from operations, which raises substantial doubt about its ability to continue as a going concern. Management s plans regarding those matters are described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ MaloneBailey, LLP

www.malone-bailey.com

Houston, Texas

April 15, 2015

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Saratoga Resources, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,911,070	$ 32,547,380
Accounts receivable	3,778,808	6,758,572
Prepaid expenses and other	1,006,758	1,056,350
Other current assets	150,000	150,000
Total current assets	15,846,636	40,512,302
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	301,399,079	286,441,663
Other	1,031,779	892,694
	302,430,858	287,334,357
Less: Accumulated depreciation, depletion, amortization and impairment	(226,716,401)	(101,088,696)
Total property and equipment, net	75,714,457	186,245,661
Other assets, net	20,350,655	21,665,830
Total assets	$ 111,911,748	$ 248,423,793
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 6,722,116	$ 5,391,648
Revenue and severance tax payable	2,711,229	3,754,812
Accrued liabilities	13,006,617	9,807,935
Derivative liabilities short term	117	837,758
Short-term notes payable	329,964	338,512
First lien notes, net of discount of $151,169 at December 31, 2014	54,448,831	-
Second lien notes, net of discount of $847,947 at December 31, 2014	124,352,053	-
Total current liabilities	201,570,927	20,130,665
Long-term liabilities		
Asset retirement obligation	16,397,804	12,649,458
Long-term debt, net of discount of $1,603,016 at December 31, 2013	-	178,196,984
Derivative liabilities	-	182,174
Total long-term liabilities	16,397,804	191,028,616
Commitment and contingencies (see notes)		

Stockholders' equity (deficit):				
Common stock, $0.001 par value; 100,000,000 shares authorized 30,986,601 and 30,946,601 shares issued and outstanding at December 31, 2014 and 2013, respectively		30,987		30,947
Additional paid-in capital		78,754,854		78,165,364
Retained deficits		(184,842,824)		(40,931,799)
Total stockholders' equity (deficit)		(106,056,983)		37,264,512
Total liabilities and stockholders' equity (deficit)	$	111,911,748	$	248,423,793

See notes to consolidated financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

AND OTHER COMPREHENSIVE LOSS

	For the Year Ended December 31, 2014	2013
Revenues:		
Oil and gas revenues	$ 52,325,716	$ 68,696,055
Oil and gas hedging	1,550,871	(1,701,569)
Other revenues	477,493	420,429
Total revenues	54,354,080	67,414,915
Operating Expense:		
Lease operating expense	24,631,620	21,685,103
Workover expense	4,537,031	2,475,541
Exploration expense	706,904	900,255
Loss on plugging and abandonment	-	701,241
Depreciation, depletion and amortization	17,853,499	17,269,349
Impairment expense	107,774,206	2,179,075
Accretion expense	1,793,865	2,552,381
Gain on revision of asset retirement obligations	(75,178)	(564,719)
General and administrative	9,549,430	9,253,600
Severance taxes	3,649,814	7,274,808
Arbitration loss	3,400,000	-
Total operating expenses	173,821,191	63,726,634
Operating income (loss)	(119,467,111)	3,688,281
Other income (expense):		
Interest income	48,328	16,197
Interest expense	(24,302,387)	(21,466,162)
Total other expense	(24,254,059)	(21,449,965)
Net loss before reorganization expenses and income taxes	(143,721,170)	(17,761,684)
Reorganization expenses	-	2,319
Net loss before income taxes	(143,721,170)	(17,764,003)
Income tax provision	189,855	8,630,456
Net loss	$ (143,911,025)	$ (26,394,459)

Other Comprehensive Income

Unrealized gain on derivative instruments		-		171,086
Total comprehensive loss	$	(143,911,025)	$	(26,223,373)
Net income per share:				
Basic	$	(4.65)	$	(0.85)
Diluted	$	(4.65)	$	(0.85)
Weighted average number of common shares outstanding:				
Basic		30,967,533		30,932,541
Diluted		30,967,533		30,932,541

See notes to consolidated financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (DEFICIT)

	Common Stock Shares		Amount		Additional Paid-in Capital		Net (Loss)		Other Comprehensive (Loss)		Total Stockholders Equity (Deficit)
Balance, December 31, 2012	30,905,101	$	30,905	$	77,140,451	$	(14,537,340)	$	(171,086)	$	62,462,930
Common stock options exercised	6,500		7		9,938		-		-		9,945
Common stock warrants exercised	35,000		35		13,815		-		-		13,850
Stock-based employee compensation	-		-		1,001,160		-		-		1,001,160
Other comprehensive income	-		-		-		-		171,086		171,086
Net loss	-		-		-		(26,394,459)		-		(26,394,459)
Balance, December 31, 2013	30,946,601	$	30,947	$	78,165,364	$	(40,931,799)	$	-	$	37,264,512
Common stock options exercised	40,000		40		61,160				-		61,200
Stock-based employee compensation	-		-		528,330		-		-		528,330
Net loss	-		-		-		(143,911,025)		-		(143,911,025)
Balance, December 31, 2014	30,986,601	$	30,987	$	78,754,854	$	(184,842,824)	$	-	$	(106,056,983)

See notes to consolidated financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2014	2013
Cash flows from operating activities:		
Net income (loss)	$ (143,911,025)	$ (26,394,459)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation, depletion and amortization	17,853,499	17,269,349
Impairment expense	107,774,206	2,179,075
Accretion expense	1,793,865	2,552,381
Amortization of debt issuance costs and debt discount	3,171,973	1,959,218
Unrealized (gain)loss on hedges	(1,640,315)	1,019,932
Stock-based compensation	528,330	1,001,160
Loss on plugging and abandonment	-	701,241
Gain on revision of asset retirement obligations	(75,178)	(564,719)
Deferred tax provision (benefit)	-	8,499,575
Changes in operating assets and liabilities:		
Accounts receivable	2,979,764	5,671,586
Prepaids and other	1,656,870	1,735,926
Accounts payable	1,961,581	(3,419,534)
Revenue and severance tax payable	(1,043,583)	(2,375,055)
Payments to settle asset retirement obligations	-	(1,229,042)
Accrued liabilities	3,898,982	(1,058,909)
Net cash provided (used) by operating activities	(5,051,031)	7,547,725
Cash flows from investing activities:		
Additions to oil and gas property	(13,638,670)	(29,776,182)
Additions to other property and equipment	(139,085)	(97,556)
Other assets	(959,571)	(1,157,161)
Net cash used by investing activities	(14,737,326)	(31,030,889)
Cash flows from financing activities:		
Proceeds from issuance of common stock	61,200	23,795
Proceeds from long term debt	-	27,300,000
Repayment of short-term notes payable	(1,615,826)	(1,558,152)
Debt issuance costs of long term debt	(293,327)	(2,037,402)
Net cash provided (used) by financing activities	(1,847,953)	23,728,241
Net increase (decrease) in cash and cash equivalents	(21,636,310)	245,067
Cash and cash equivalents - beginning of period	32,547,380	32,302,313
Cash and cash equivalents - end of period	$ 10,911,070	$ 32,547,380

Supplemental disclosures of cash flow information:				
Cash paid for income taxes	$	157,355	$	130,881
Cash paid for interest		19,765,423		19,815,440
Non-cash investing and financing activities:				
Unrealized gain(loss) on derivative instruments	$	-	$	171,086
Accounts payable for oil and gas additions		920,824		1,551,937
Accrued liabilities for oil and gas additions		-		79,800
Revisions to asset retirement obligations		2,004,893		(6,509,866)
Additions to asset retirement obligations		24,766		62,808
Prepaid insurance financed with debt		1,607,278		1,523,305
Senior secured notes exchanged for first lien notes		-		23,000,000

See notes to consolidated financial statements.

Saratoga Resources, Inc.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

Saratoga Resources, Inc. is an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of natural gas and crude oil properties.

Our financial statements include the accounts of Saratoga Resources, Inc., a Texas corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to Saratoga , Company we, us or our are to Saratoga Resources, Inc., and its subsidiaries.

Accounting for Reorganization

On March 31, 2009, Saratoga and its subsidiaries, all of which are 100%-owned: Harvest Oil and Gas, LLC, The Harvest Group, LLC, Lobo Operating, Inc. and Lobo Resources, Inc. (collectively the Debtors), filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code. The Debtors operated under Chapter 11 protection from the filing date on March 31, 2009 until the effective date of the Debtors plan of reorganization (the Plan of Reorganization) and exit from Chapter 11 on May 14, 2010. The accompanying consolidated financial statements of Saratoga have been prepared in accordance with FASB ASC 852, *Reorganizations*. The Company incurred expenses relating to the Plan of Reorganization of $2,319, during the year ended December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Material estimates that are particularly susceptible to significant change in the near term include the determination of depreciation, depletion and amortization, plugging and abandonment liabilities, and the valuation of oil and gas property.

Reclassifications

Certain reclassifications have been made to prior years reported amounts in order to conform to the current year presentation. These reclassifications did not impact our net income, stockholders equity or cash flows.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. Prices for crude oil have recently declined materially. Any continued and extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Revenue Recognition

We recognize oil and gas revenue from interests in producing wells as the oil and gas is sold. Revenue from the purchase, transportation, and sale of natural gas is recognized upon completion of the sale and when transported volumes are delivered. We recognize revenue related to gas balancing agreements based on the sales method. Our net imbalance position at December 31, 2014 and 2013 was immaterial.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash, cash equivalents and any marketable securities. The Company had cash deposits of approximately $10.7 million and $32.3 million in excess of FDIC insured limits at December 31, 2014 and 2013, respectively. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Major Customers

Sales of oil and gas production to Shell Trading (US) Company and Shell Energy North America (US), L.P. (collectively Shell) and Chevron Natural Gas, Inc. and Chevron Products Company (collectively Chevron) accounted for 50% and 37%, respectively, of our consolidated sales in 2014. Sales of oil and gas production to Shell and Chevron accounted for 57% and 32%, respectively, of our consolidated sales in 2013. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are readily available.

Other Revenue

Other revenues consist principally of production handling charges and an insurance reimbursement for a loss incurred in a prior year.

Cash and Cash Equivalents

For the purpose of the Statement of Cash Flows, we consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable

Receivables are carried at original invoice amount. Uncollectible accounts receivable are charged directly against earnings when they are determined to be uncollectible. Use of this method does not result in a material difference from the valuation method required by generally accepted accounting principles. At December 31, 2014 and 2013, no reserve for allowance for doubtful accounts was needed.

Oil and Gas Operations

Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for the classification of reserves as proved, the associated leasehold costs are reclassified into proved properties.

Oil and gas exploration costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venture approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Oil and gas development costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Depletion expense for the years ended December 31, 2014 and 2013 was $17,741,322 and $17,145,473, respectively.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that an asset may be impaired, Saratoga compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on Saratoga s estimate of future natural gas and crude oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. During the years ended December 31, 2014 and 2013, Saratoga recorded impairment expense of $107,774,206 and $2,179,075, respectively. The impairment expense during 2014 reflected the reclassification of certain reserves out of the proved undeveloped category and into the probable category due to application of the SEC s five year rule and the steep decline in commodity prices which resulted in the expected undiscounted future cash flows at a producing field level to be less than the unamortized capitalized cost of assets in several fields. The impairment expense during 2013 related to the loss of a lease, and associated reserves, at one field.

We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have a future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable and estimable.

See Note 8 Oil and Gas Assets .

Derivative Instruments and Hedging Activities

All derivative instruments are recorded in our 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 has been designated as a cash flow hedge and specific cash flow hedge accounting criteria are met. Under cash flow hedge accounting, unrealized gains and losses are reflected in shareholders equity as accumulated other comprehensive income (loss) (OCI) until the forecasted transaction occurs. The derivative s gains or losses are then offset against related results on the hedged transaction in the statements of operations.

The 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 hedging 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, we assess hedge effectiveness 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. We record hedge ineffectiveness in oil and gas hedging. At December 31, 2014, none of our hedges qualified for hedge accounting. At December 31, 2013, none of our hedges met the statistical tests for effectiveness.

We designate our commodity derivative instruments as cash flow hedges. Changes in the fair value commodity derivative instruments used as cash flow hedges are reported in OCI, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recognized in earnings.

See Note 6 Derivative Instruments and Hedging Activities .

Depreciation of Other Property and Equipment

Furniture, fixtures, equipment, and other assets are depreciated using the straight-line method over the estimated useful lives of the assets. The estimated lives of these assets range from three to five years.

Debt Issuance Costs and Debt Discount

Debt issuance costs incurred are capitalized and amortized, using the interest method, over the term of the related debt.

The amount of discount at which debt is has been issued is amortized into interest expense, using the interest method, over the term of the related debt.

Stock Based Compensation

In accordance with the provisions of the Stock Compensation Topic of the ASC (ASC Topic 718), Saratoga measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Income Taxes

We account for income taxes under the provisions of the Income Taxes Topic of the ASC (ASC Topic 740). ASC Topic 740 requires the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis.

We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. At December 31, 2014 and 2013, a valuation allowance was provided for the entire balance of the net deferred tax asset in the amount of $64,480,235 and $13,837,850, respectively. In addition we routinely assess uncertain tax positions, and accrue for tax positions that are not more-likely-than-not to be sustained upon examination by taxing authorities.

See Note 12 Income Taxes .

Net Income Per Share

Basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted net income per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities (see Note 11 Common Stock).

Recently Issued Accounting Standards and Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014 09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted and entities have the option of using either a retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern (ASU 2014-15). ASU 2014-15 provides guidance about management s responsibility to evaluate whether there is substantial doubt about an entity s ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. The Company plans to adopt ASU 2014-15 prospectively for the annual period ending December 31, 2016. Pursuant to ASU 2014-15, the Company is required to consider whether there are adverse conditions or events that raise substantial doubt about the Company s ability to continue as a going concern within one year after the date that the financial statements are issued and the probability that management s plans will mitigate the adverse conditions or events (if any). Adverse conditions or events would include, but not be limited to, negative financial trends (such as recurring operating losses, working capital deficiencies, or insufficient liquidity), a need to restructure outstanding debt to avoid default, and industry developments (for example commodity price declines and regulatory changes).

NOTE 2. GOING CONCERN

The accompanying consolidated financial statements have been prepared in conformity with accounting principles accepted in the United States of America which contemplate the continuation of the Company as a going concern. The Company incurred a loss from operations of $119,467,111 for the year ended December 31, 2014 and has a working capital deficit of $185,724,291 at December 31, 2014. These conditions raise substantial doubt as to the Company s ability to continue as a going concern. These financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

To address these matters, the Company is seeking to restructure its debt, or find alternative sources of financing. There can be no assurance that the Company will be successful in its efforts.

NOTE 3. CHAPTER 11 REORGANIZATION

On March 31, 2009, Saratoga and its subsidiaries, all of which are 100%-owned: Harvest Oil and Gas, LLC, The Harvest Group, LLC, Lobo Operating, Inc. and Lobo Resources, Inc. (collectively the Debtors), filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code.

On May 14, 2010, the Company satisfied all of the conditions set forth in its Plan of Reorganization and the Company exited from bankruptcy.

During the years ended December 31, 2013, the Company incurred $2,319, in reorganization costs.

NOTE 4. OTHER ASSETS

Other assets consist of the following:

	December 31,			
		2014		2013
Site specific trust accounts P&A escrow	$	5,564,129	$	5,521,913
Debt issuance cost, net		4,077,060		6,351,806
Restricted cash P&A bond		10,628,903		9,738,353
Other		80,563		53,758
	$	20,350,655	$	21,665,830

Site Specific Trust Accounts P&A Escrow

The Company maintains an escrow agreement that has been established for the purpose of assuring maintenance and administration of a performance bond which secures certain plugging and abandonment obligations assumed in the acquisition of oil and gas properties in certain fields. Changes in the escrow accounts reflect additional contributions and interest earned during 2014. See Note 9 Asset Retirement Obligations .

Debt Issuance Costs, Net

The Company capitalizes certain debt issuance costs and amortizes those costs as additional interest expense over the lives of the associated debt. Net debt issuance costs at December 31, 2014 and 2013 reflect the issuance of the 12½% Second Lien Notes in December 2012 and July 2011 and the issuance of the 10% First Lien Notes in November 2013. See Note 5 Debt .

Restricted Cash P&A Bond

Restricted Cash P&A Bond consists of cash collateral held in escrow to assure maintenance and administration of performance bonds which secures certain plugging and abandonment obligations imposed by state law. The cash collateral is reflected as a long term asset to correspond with the expected timing of the related asset retirement obligation liability. See Note 9 Asset Retirement Obligations .

NOTE 5. DEBT

Debt consists of the following:

	December 31, 2014	December 31, 2013
10% First Lien Notes due 2015	$ 54,600,000	$ 54,600,000
12 ½% Second Lien Notes due 2016	125,200,000	125,200,000
Less unamortized discount	(999,116)	(1,603,016)
	$ 178,800,884	$ 178,196,984

10.0% First Lien Notes

In November 2013, the Company, and its wholly-owned subsidiaries (the Guarantors), issued $54.6 million in aggregate principal amount of 10.0% Senior Secured Notes due 2015 (the First Lien Notes) to two institutional accredited investors (the Purchasers).

The First Lien Notes were issued pursuant to Purchase Agreements (the Purchase Agreement), and under an Indenture (the First Lien Indenture), by and among the Company, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (the First Lien Trustee). The First Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed (the Guarantees) on a senior secured basis by the Guarantors and will rank equally in right of payment with our, and the Guarantors , existing and future senior indebtedness and senior in right of payment to Second Lien Notes (as defined below).

The purchase price for the First Lien Notes and Guarantees was 100% of their principal amount. We received net proceeds from the issuance and sale of the First Lien Notes of approximately $25.4 million, after commissions and estimated offering expenses, and the surrender for retirement by the Purchasers of $27.3 million in face amount of 12½% Senior Secured Notes (the Second Lien Notes).

The First Lien Notes mature on December 31, 2015, and interest, accruing at 10% per annum, is payable on the First Lien Notes on March 31, June 30, September 30 and December 31 of each year, commencing December 31, 2013.

The First Lien Indenture includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Company has the option to redeem all or a portion of the First Lien Notes at any time at 100% of the principal amount to be redeemed plus accrued and unpaid interest. Upon the occurrence of a change of control, we are required to offer to purchase the First Lien Notes at a price equal to 101% of the aggregate principal amount of First Lien Notes repurchased plus accrued and unpaid interest. Further, upon the occurrence of certain asset sales, we are required to provide notice of the same and are required to offer to purchase a defined portion of the First Lien Notes at a price equal to 100% of the principal amount of First Lien Notes repurchased plus accrued and unpaid interest.

In connection with the issuance and sale of the First Lien Notes, the Company, the First Lien Trustee and The Bank of New York Mellon Trust Company, N.A., in its capacity as trustee and collateral under the Second Lien Documents (as defined below)(the Second Lien Trustee) entered into an Intercreditor Agreement (the Intercreditor Agreement). Pursuant to the Intercreditor Agreement, parties agreed that the lien with respect to collateral securing the First Lien Indenture and related First Lien Notes and Guarantees (the First Lien Obligations) shall be senior in right, priority, operation, effect and all other respects to any lien with respect to collateral securing the obligations under that certain Indenture dated as of June 12, 2011, as supplemented or amended from time to time thereafter (the Second Lien Indenture), by and among our company, the Guarantors named therein and the Second Lien Trustee, and the related Second Lien Notes in the aggregate amount of $125.2 million (the Second Lien Obligations).

Interest payable and owing as of December 31, 2014, in the amount of $1,365,000, was not paid as of the due date. Such interest was subsequently paid in connection with a Forbearance Agreement to First Lien Indenture. See Note 14. Subsequent Events.

12½% Second Lien Notes

In July 2011, the Company and the Guarantors entered into a Purchase Agreement with Imperial Capital, LLC (the Initial Purchaser), relating to the issuance and sale of $127.5 million in aggregate principal amount of 12½% Senior Secured Notes due 2016. The Second Lien Notes were sold at 98.221% of par in a transaction exempt from the registration requirements of the Securities Act and were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

In December 2012, the Company and the Guarantors entered into another Purchase Agreement with the Initial Purchaser, relating to the issuance and sale of an additional $25 million in aggregate principal amount of the Second Lien Notes. The Second Lien Notes were sold at 98.58% of par in a transaction exempt from the registration requirements of the Securities Act and were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

The Second Lien Notes were issued pursuant to the Second Lien Indenture among the Company, the Guarantors named therein and Second Lien Trustee, as trustee and collateral agent and, with respect to the Second Lien Notes issued in 2012, a First Supplemental Indenture, dated December 4, 2012. The Second Lien Notes are the senior secured obligations of the Company and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with the Company s and the Guarantors existing and future senior indebtedness, subject, however, to the Intercreditor Agreement pursuant to which the First Lien Notes are senior in right, priority, operation and effect to the lien securing the Second Lien Notes.

The Second Lien Notes mature on July 1, 2016, and interest is payable on January 1 and July 1 of each year.

The Second Lien Indenture includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Company has the option to redeem all or a portion of the Second Lien Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest.

Interest accrued and owing as of January 1, 2015, in the amount of $7,825,000, was not paid on its due date and, as a result, the Second Lien Notes are in default and are included as a current liability in the accompanying consolidated financial statements. The Company and the principal holders of the Second Lien Notes entered into a Forbearance Agreement to Second Lien Debenture in January 2015. See Note 14- Subsequent Events.

NOTE 6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Objective and Strategies for Using Commodity Derivative Instruments

The Company periodically enters into commodity derivative instruments, primarily fixed price swaps, to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company. The fixed price swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) 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. We 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. The amount payable by us, if the floating price is above the fixed price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed price with respect to each calculation period. The amount payable by the counterparty, if the floating price is below the fixed price, is the product of the notional quantity per calculation period and the excess of the fixed price over the floating price with respect to each calculation period.

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

See Note 7 Fair Value Measurements for a discussion of the methods and assumptions used to estimate the fair values of our commodity derivative instruments.

The Company utilizes hedge accounting for our commodity derivative instruments, which are designated as cash flow hedges.

Counterparty Credit Risk

Commodity derivative instruments expose us to counterparty credit risk. The Company s commodity derivative instruments were with one and two counterparties at December 31, 2014 and 2013, respectively. We monitor and manage our level of financial exposure with respect to the counterparties we use. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. However, we are not able to predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk.

As of December 31, 2014, the Company had the following hedge contracts outstanding:

Instrument	**Beginning Date**	**Ending Date**	**Fixed Price**	**Strike Price**	**Premium**	**Total Bbls**
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	22,500
						22,500

The following table presents the fair value of the Company s commodity derivative instruments at December 31, 2014 and 2013:

Description	December 31, 2014		December 31, 2013	
Current liabilities				
Commodity derivatives	$	117	$	837,758
	$	117	$	837,758

Description	December 31, 2014		December 31, 2013	
Long-term liabilities				
Commodity derivatives	$	-	$	182,174
	$	-	$	182,174

The following tables present the effect of commodity derivative instruments on our consolidated statements of operations and comprehensive income (loss) for the years ended December 31, 2014 and 2013:

Description	For the Year Ended December 31, 2014		2013	
Unrealized mark-to-market loss	$	(117)	$	(1,019,932)
Realized gain (loss) on settlements		1,550,754		(681,637)
Total gain (loss) on commodity derivative instruments	$	1,550,637	$	(1,701,569)

Description	For the Year Ended December 31, 2014		2013	
Unealized mark-to-market gain(loss) in other comprehensive income (loss)	$	-	$	171,086
Total other comprehensive income (loss)	$	-	$	171,086

NOTE 7. FAIR VALUE MEASUREMENTS

The Company has various financial instruments that are measured at fair value in the financial statements, including commodity derivatives. The Company s financial assets and liabilities are measured using input from three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

Level 1 Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

Level 2 Inputs include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the assets or liability and inputs that are derived principally from, or corroborated by, observable market data by correlation or other means (market corroborated inputs).

Level 3 Unobservable inputs that reflect the Company s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, using internal and external data.

The following table presents the Company s assets and liabilities recognized in the balance sheet and measured at fair value on a recurring basis as of December 31, 2014:

Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Liabilities:				
Commodity derivatives	$	$ 117	$	$ 117
	$	$ 117	$	$ 117

The following table presents the Company s assets and liabilities recognized in the balance sheet and measured at fair value on a recurring basis as of December 31, 2013:

Description	Level 1	Level 2	Level 3	Total
Liabilities:				
Commodity derivatives	$	$ 1,019,932	$	$ 1,019,932
	$	$ 1,019,932	$	$ 1,019,932

The Company uses various commodity derivative instruments, including fixed price swaps. We consider the fair value of our commodity derivative instruments to be level 2 on the fair value hierarchy. The fair value of commodity derivatives is determined using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data.

NOTE 8. OIL AND GAS ASSETS

Property and equipment consisted of the following:

	December 31, 2014	December 31, 2013
Oil and gas properties (proved):		
Gross oil and gas properties (proved)	$ 301,399,079	$ 286,441,663
Accumulated depreciation, depletion, amortization and impairment	(225,896,843)	(100,381,317)
Net oil and gas properties (proved)	75,502,236	186,060,346
Other property and equipment	1,031,779	892,694
Accumulated depreciation and amortization	(819,558)	(707,379)
Net other property and equipment	212,221	185,315
Net property and equipment	$ 75,714,457	$ 186,245,661

At December 31, 2014, there were $1,617,635 in costs associated with prospects, primarily federal leases in the shallow Gulf of Mexico shelf, which were included in oil and gas properties, but were not yet included in the depletion calculation.

During the year ended December 31, 2014, the Company recorded impairment expense in the amount of $107,774,206. The impairment expense during 2014 reflected the reclassification of certain reserves out of the proved undeveloped category and into the probable category due to application of the SEC s five year rule and the steep decline in commodity prices which resulted in the expected undiscounted future cash flows at a producing field level to be less than the unamortized capitalized cost of assets in several fields.

During the year ended December 31, 2013, The Company recorded impairment expense in the amount $2,179,075. Impairment expense during 2013 related to the loss of a lease, and associated reserves, at one field.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company accounts for plugging and abandonment costs in accordance with FASB ASC 410-20, Accounting for Asset Retirement Obligations.

The Company maintains an escrow agreement that has been established for the purpose of assuring maintenance and administration of a performance bond which secures certain plugging and abandonment obligations assumed in the acquisition of oil and gas properties in certain fields.

At December 31, 2014 and 2013, the amount of the escrow account totaled $5.6 million and $5.5 million, respectively and is shown as other assets on the Company s balance sheet. See Note 4 Other Assets .

During the years ended December 31, 2014 and 2013, downward revisions in the asset retirement obligations relating to certain properties exceeded the carrying amounts of the properties. Accordingly, during the years ended December 31, 2014 and 2013 the excess amounts, totaling $75,178 and $564,719, respectively, were recognized as gains.

During the year ended December 31, 2013, plugging and abandonment costs related to two properties exceeded the amounts reflected in the asset retirement obligation liability. The wells plugged were the deepest and highest pressure wells in our entire inventory of wells to be plugged and included certain unanticipated conditions. Accordingly, during the year ended December 2013, the excess amount, which was $701,241 was recognized as a loss.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations are as follows:

Balance at December 31, 2012	$ 17,071,936
Accretion expense	2,552,381
Additions	62,808
Revisions	(6,509,866)
Settlements	(527,801)
Balance at December 31, 2013	$ 12,649,458
Accretion expense	1,793,865
Additions	24,766
Revisions	1,929,715
Settlements	-
Balance at December 31, 2014	$ 16,397,804

NOTE 10. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

We have commitments under a non-cancellable operating lease agreements for our offices in Houston, Texas and Covington, Louisiana.

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2014 and 2013 was $262,250 and $244,648, respectively.

We have certain plugging and abandonment, reclamation, restoration, and clean up liabilities and obligations related to our oil and gas properties. To secure these liabilities, we maintain $7,750,000 in letters of credit. The letters of credit are secured by cash collateral.

At December 31, 2014, total minimum commitments from debt, long-term non-cancelable operating leases, asset retirement obligations and other purchase obligations are as follows:

	Payments due by period				
	Total	**2015**	**2016 2017**	**2018 2019**	**Thereafter**
Debt	$ 188,990,000	$ 188,990,000	$ -	$ -	$ -
Operating leases	432,667	168,167	264,500	-	-
Asset retirement obligations	56,239,500	-	5,695,000	348,000	50,196,500
Total	$ 245,662,167	$ 189,158,167	$ 5,959,500	$ 348,000	$ 50,196,500

Contingencies

From time to time the Company may become involved in litigation in the ordinary course of business. At December 31, 2014, except as noted, the Company s management was not aware, and as of the date of this report is not aware of any such litigation that could have a material adverse effect on its results of operations, cash flows or financial condition.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks. The Company is not aware of any environmental claims existing as of December 31, 2014, which have not been provided for, covered by insurance or otherwise have a material impact on its financial position or results of operations. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental laws will not be discovered on the Company s properties.

The Harvest Group, LLC, et al. v. Brian Carl Albrecht; Harvest Operating LLC v. The Harvest Group, LLC, et al.

In February 2010, the Company filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group LLC and/or Harvest Oil & Gas, LLC. The complaint alleged breach of the Purchase and Sale Agreements with the former owners arising from the underpayment or nonpayment of royalties to the State of Louisiana for periods prior to the Company s acquisition of the Harvest Companies and related claims for damages. The claims against all parties other than Brian Carl Albrecht were subsequently settled and the claim against Mr. Albrecht was converted to an arbitration proceeding.

Harvest Operating, LLC, a company controlled by Mr. Albrecht, brought a separate cause of action against The Harvest Group, LLC, Harvest Oil & Gas, LLC and Saratoga Resources, Inc. (the Saratoga Parties), which cause of action was consolidated with the arbitration proceedings noted above. Harvest Operating s cause of action asserted a claim for damages based on the alleged wrongful termination of rights to use a pipeline owned and operated by the Saratoga Parties and the loss in value of a property operated by Harvest Operating based on its inability to transport production from that property via the pipeline in question.

The consolidated arbitration proceeding was conducted before a single arbitrator and, in August 2014, the arbitrator issued an Award and Reasons ruling (1) in favor of Saratoga, as relates to the royalty claim, and awarding to Saratoga $355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim, and awarding to Harvest Operating $3,757,050. As a result of such award, the Company recorded an arbitration award expense and an accrued liability of $3.4 million.

The Company believes that the award based on the pipeline use claim is wholly unsupported by the facts or the law. In November 2014, Saratoga filed a motion with the arbitrator to reconsider and clarify the arbitration award. Separately, in November 2014, Saratoga filed a Motion for Clarification and Remittitur in the 19th District Court of East Baton Rouge Parish, Louisiana. Both the motion with the arbitrator and the Motion in the District Court seek to vacate the arbitrator s award relating to the pipeline claim on multiple grounds. In December 2014, the arbitrator agreed to hear arguments as to the authority and grounds for reconsidering the arbitration award and the arbitrator s decision in that matter is pending.

Also, in November 2014, Saratoga filed a separate cause of action against Brian Albrecht in the 24th District Court of Jefferson Parish, Louisiana. The cause of action alleges breach of contract on the part of Mr. Albrecht and seeks damages in an amount equal to those awarded in the above arbitration proceeding. Saratoga asserts that the Purchase and Sale Agreement under which Saratoga secured beneficial ownership of the pipeline that is subject of the arbitration proceeding and the claims of Harvest Operating was illusory in that, if the reasoning of the arbitration award were to stand, Saratoga would not have received the rights associated with beneficial ownership and control of the pipeline and that, by withholding from Saratoga the ordinary rights associated with ownership of the pipeline, Mr. Albrecht was in breach of the terms of the Purchase and Sale Agreement.

NOTE 11. COMMON STOCK

Net Income per Common Share

A reconciliation of the components of basic and diluted net income per common share is presented in the tables below:

	For the Year Ended December, 31	
	2014	**2013**
Income (loss) attributable to common stock	$ (143,911,025)	$ (26,394,459)
Weighted average number of shares outstanding, basic	30,967,533	30,932,541
Incremental shares from assumed conversion of dilutive stock options and warrants	-	-
Weighted average number of shares outstanding, diluted:	30,967,533	30,932,541
Net Income (loss) per share, basic	(4.65)	(0.85)
Net Income (loss) per share, diluted	(4.65)	(0.85)
Number of antidilutive stock options and warrants excluded from calculation above	1,799,498	1,754,497

Common Stock Activity

During the year ended December 31, 2013, the Company issued an aggregate of 6,500 shares of common stock upon the exercise of outstanding stock options by a former employee. The shares were issued for gross proceeds of $9,945, or $1.53 a share. See -Stock Option Activity below.

During the year ended December 31, 2013, the Company issued an aggregate of 35,000 shares of common stock upon the exercise of outstanding warrants for gross proceeds of $13,850, or $0.40 per share. See -Warrant Activity below.

During the year ended December 31, 2014, the Company issued an aggregate of 40,000 shares of common stock upon the exercise of outstanding stock options by a former employee. The shares were issued for gross proceeds of $61,200, or $1.53 per share. See -Stock Option Activity below.

Stock-Based Compensation

The Company periodically grants restricted stock and stock options to employees, directors and consultants. The Company is required to make estimates of the fair value of the related instruments when granted and recognize expense over the period benefited, usually the vesting period.

In September 2011, the Company s board of directors adopted, and in June 2012 the Company s stockholders approved, the Saratoga Resources, Inc. 2011 Omnibus Equity Plan (the 2011 Plan). The 2011 Plan reserves a total of 3,000,000 shares for issuance to eligible employees, officers, directors and other service providers pursuant to grants of options, restricted stock, performance stock and other equity based compensation agreements.

In conjunction with the adoption of the 2011 Plan, the Company s board of directors approved the termination of the Saratoga Resources, Inc. 2008 Long-term Incentive Plan (the 2008 Plan) and the Saratoga Resources, Inc. 2006 Employee and Consultant Stock Plan (the 2006 Plan). At the time of their termination, no awards were outstanding under the 2008 Plan or the 2006 Plan.

Stock Option Activity

In April 2013, the Company s management approved a stock option grant to purchase an aggregate of 75,000 shares of common stock to two non-executive employees. The options are exercisable for a term of seven years at prices ranging from $2.34 to $2.42 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $178,200. The options were valued using the Black-Scholes model with the following assumptions: 240% volatility; 4.5 year estimated life; zero dividends; 0.60% to 0.62% discount rate; and, quoted stock price and exercise price of $2.34 to $2.42.

In June 2013, the Company s board of directors approved a stock option grant to purchase an aggregate of 500,000 shares of common stock to two executive officers. The options are exercisable for a term of five years at $3.00 per share and vest 1/8 per quarter. The grant date value of the options was $505,000. The options were valued using the Black-Scholes model with the following assumptions: 83% volatility; 3.06 year estimated life; zero dividends; 0.57% discount rate; and, quoted stock price of $2.18.

In June 2013, the Company s board of directors approved a stock option grant to purchase an aggregate of 105,000 shares of common stock to non-employee directors. The options are exercisable for a term of seven years at $2.18 per share and vest ½ on the date of grant and ½ on the first anniversary of the grant date. The grant date value of the options was $174,300. The options were valued using the Black-Scholes model with the following assumptions: 121% volatility; 3.75 year estimated life; zero dividends; 0.77% discount rate; and, quoted stock price and exercise price of $2.18.

In July 2013, the Company s management approved a stock option grant to purchase an aggregate of 60,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at price of $1.53 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $90,600. The options were valued using the Black-Scholes model with the following assumptions: 231% volatility; 4.5 year estimated life; zero dividends; 1.18% discount rate; and, quoted stock price and exercise price of $1.53.

In August 2013, the Company s management approved a stock option grant to purchase an aggregate of 90,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at price of $1.72 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $150,300. The options were valued using the Black-Scholes model with the following assumptions: 204% volatility; 4.5 year estimated life; zero dividends; 1.18% discount rate; and, quoted stock price and exercise price of $1.72.

During the year ended December 31, 2013, stock options to purchase 6,500 shares of common stock at $1.53 per share were exercised for cash proceeds totaling $9,945.

In February 2014, the Company s management approved a stock option grant to purchase an aggregate of 90,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.32 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $96,300. The options were valued using the Black-Scholes model with the following assumptions: 121% volatility; 4.5 year estimated life; zero dividends; 1.36% discount rate; and, quoted stock price and exercise price of $1.32.

In April 2014, the Company s management approved a stock option grant to purchase an aggregate of 60,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.22 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $57,000. The options were valued using the Black-Scholes model with the following assumptions: 113% volatility; 4.5 year estimated life; zero dividends; 1.47% discount rate; and, quoted stock price and exercise price of $1.22.

In April 2014, the Company s management approved a stock option grant to purchase an aggregate of 90,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.18 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $70,200. The options were valued using the Black-Scholes model with the following assumptions: 92% volatility; 4.1 year estimated life; zero dividends, 1.25% discount rate; and, quoted stock price and exercise price of $1.18.

In May 2014, the Company s management approved a stock option grant to purchase an aggregate of 60,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.30 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $47,400. The options were valued using the Black-Scholes model with the following assumptions: 83% volatility; 4.1 year estimated life; zero dividends; 1.26% discount rate; and, quoted stock price and exercise price of $1.30.

In May 2014, the Company s board of directors approved stock option grants to purchase an aggregate of 90,000 shares of common stock to two executive officers. The options are exercisable for a term of seven years at $1.30 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $71,100. The options were valued using the Black-Scholes model with the following assumptions:

83% volatility; 4.1 year estimated life; zero dividends; 1.26% discount rate; and, quoted stock price and exercise price of $1.30.

In June 2014, the Company s board of directors approved a stock option grant to purchase an aggregate of 105,000 shares of common stock to non-employee directors. The options are exercisable for a term of seven years at $1.89 per share and vest 1/2 on the date of grant and 1/2 on the first anniversary of the grant date. The grant date value of the options was $103,950. The options were valued using the Black-Scholes model with the following assumptions: 72% volatility; 3.75 year estimated life; zero dividends; 1.24% discount rate; and, quoted stock price and exercise price of $1.89.

In September 2014, the Company s management approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to two non-executive employees. The options are exercisable for a term of seven years at $1.47 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $29,700. The options were valued using the Black-Scholes model with the following assumptions: 90% volatility; 4.5 year estimated life; zero dividends; 1.62% discount rate; and, quoted stock price and exercise price of $1.47.

During the year ended December 31, 2014, stock options to purchase 40,000 shares of common stock at $1.53 per share were exercised for cash proceeds totaling $61,200.

Stock based compensation expense attributable to common shares and grants of options was $528,330 and $1,001,160, during the years ended December 31, 2014 and 2013, respectively. The unamortized amount of stock-based compensation that had not been recorded was $286,407 and $614,885 as of December 31, 2014 and 2013, respectively.

The following table presents the options outstanding at December 31, 2014:

	Number of Shares Underlying Options		Weighted Average Exercise Price per Share		Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (in Years)		Aggregate Intrinsic Value [(1)]
Outstanding at December 31, 2012	784,000	$	3.66	$	3.65	6.5	$	474,240
Granted	830,000		2.60		1.32	5.2		-
Exercised	(6,500)		1.53		1.53	-		-
Forfeited	-		-		-	-		-
Outstanding at December 31, 2013	1,607,500	$	3.13	$	2.46	5.4	$	39,000
Granted	525,000		1.40		0.91	6.4		-
Exercised	(40,000)		1.53		1.53	-		-
Forfeited	(440,000)		3.21		3.12	-		-
Outstanding at December 31, 2014	1,652,500		2.59		1.81	4.8		-
Exercisable at December 31, 2014	1,045,000	$	3.03	$	2.18	4.4	$	-

(1)

The intrinsic value of an option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option. On December 31, 2014, the last reported sales price of our common stock on the NYSE MKT was $0.217 per share.

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

	Options Outstanding and Exercisable		
Exercise Price	Number of Shares Underlying	Weighted Average Exercise	Weighted Average Remaining

	Options	Price per Share	Contractual Life (in Years)
$ 0.36	50,000	$ 0.02	0.20
1.30	50,000	0.06	0.30
1.39	10,000	0.01	0.01
1.53	20,000	0.03	0.11
1.71	2,500	0.04	0.01
1.72	30,000	0.05	0.16
1.89	52,500	0.09	0.32
2.18	105,000	0.22	0.55
2.34	5,000	0.01	0.03
2.42	20,000	0.05	0.10
2.75	30,000	0.08	0.18
3.00	435,000	1.25	1.54
3.05	70,000	0.20	0.21
4.62	30,000	0.13	0.11
5.11	30,000	0.15	0.11
6.65	105,000	0.67	0.45
	1,045,000	$ 3.03	4.39

Warrant Activity

In May and July 2013 service providers exercised warrants, originally issued in 2008, to purchase 35,000 shares of common stock at prices ranging from $0.17 to $1.75 per share for total proceeds of $13,850.

The following table presents the warrants outstanding at December 31, 2014:

	Number of Shares Underlying Warrants	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value [1]
Outstanding at December 31, 2012	572,628	$ 5.14	$ 3.22	0.8	$ 132,900
Granted	-	-	-	-	-
Exercised	(35,000)	0.40	0.22	-	-
Forfeited	(390,630)	5.00	2.69	-	-
Outstanding at December 31, 2013	146,998	$ 6.64	$ 5.33	0.8	$ -
Granted	-	-	-	-	-
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at December 31, 2014	146,998	$ 6.64	$ 5.33	0.36	$ -
Exercisable at December 31, 2014	146,998	$ 6.64	$ 5.33	0.36	$ -

(1)

The intrinsic value of a warrant is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the warrant. On December 31, 2014, the last reported sales price of our common stock on the NYSE MKT was $0.217 per share.

The following table summarizes information about stock warrants outstanding and exercisable at December 31, 2014:

	Warrants Outstanding and Exercisable		
Exercise Price	Number of Shares Underlying Warrants	Weighted Average Exercise Price per	Weighted Average Remaining Contractual

				Share	Life (in Years)
$	3.00	40,000	$	0.82	0.08
	8.00	106,998		5.82	0.28
		146,998	$	6.64	0.36

NOTE 12. INCOME TAXES

The Company is subject to income tax in the United States. Current tax obligations associated with our provision for income taxes are reflected in the accompanying Balance Sheet as component of Accrued liabilities and the deferred tax obligations are reflected in Deferred income taxes .

Our effective tax rates were different than our federal statutory tax rate due to state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Our provision (benefit) for income taxes at December 31, 2014 and 2013 consisted of the following:

		2014		2013
Current:				
Federal	$	-	$	-
State		189,855		130,881
		189,855		130,881
Deferred:				
Federal		-		8,499,575
State		-		-
		-		8,499,575
Total tax provision (benefit)	$	189,855	$	8,630,456

The U.S. federal statutory income tax rate is reconciled to the effective rate at December 31, 2014 and 2013 as follows:

	2014	2013
Income tax expense at U.S. federal statutory rate	35.0 %	35.0 %
Valuation allowance	(35.0)%	(77.9)%
State and local income taxes, net of federal income tax benefit	-	-
Permanent differences	-	(0.4)%
Temporary differences	(0.1)%	(5.3)%
Effective tax rate	(0.1)%	(48.6)%

The components of the net deferred tax assets (liabilities) at December 31, 2014 and 2013 are as follows:

	2014	2013
Deferred tax asset		
Net operating loss	$ 40,218,636	$ 25,864,942
Stock-based compensation	2,712,889	2,527,973
Debt issuance cost (amortization)	1,245,012	1,245,012
Depletion on oil and gas properties	19,784,120	-
Derivatives	416,856	59,880
Depreciation and amortization	(6,802)	(12,970)
Capital loss carryover	94,936	94,936
Charitable contributions	14,588	14,588
Total deferred tax assets	64,480,235	29,794,361
Deferred tax liability		
Depletion on oil and gas properties	-	15,956,511
Total deferred tax liabilities	-	15,956,511
Less: valuation allowance	64,480,235	13,837,850
Deferred tax asset (liability)	$ -	$ -

At December 31, 2014, we had $114.9 million of federal net operating loss, or NOL, carryforwards; the federal NOL carryforwards have expiration dates through the year 2034.

We recognize the expected future tax benefit from deferred tax assets when the tax benefit is considered to be more likely than not of being realized. Otherwise, a valuation allowance is applied against deferred tax assets reducing the value of such assets. Assessing the recoverability of deferred tax assets requires management to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecasted income from operations and the application of existing tax laws in each jurisdiction. Oil and gas price estimates are a key component used in the determination of our ability to realize the expected future benefit of our deferred tax assets. To the extent that future taxable income differs significantly from estimates as a result of a decline in oil and gas prices or other factors, our ability to realize the deferred tax assets could be impacted. Additionally, significant future issuances of common stock or common stock equivalents could limit our ability to utilize our net operating loss carryforwards pursuant to Section 382 of the Internal Revenue Code. Future changes in tax law or changes in ownership structure could limit our ability to utilize our recorded tax assets. At December 31, 2014, a valuation allowance was provided for the entire balance of the net deferred tax asset in the amount of $64,190,333.

NOTE 13. SUPPLEMENTAL OIL AND GAS DISCLOSURES - UNAUDITED

Capitalized costs for our oil and gas producing activities consisted of the following at December 31, 2014 and 2013:

		2014		**2013**
Proved properties	$	301,399,079	$	286,441,663
Unproved properties		-		-
		301,399,079		286,441,663
Accumulated depreciation, depletion, amortization and impairment		(225,896,843)		(100,381,317)
Net capitalized costs	$	75,502,236	$	186,060,346

Costs incurred for oil and gas property acquisitions, exploration and development for the years ended December 31, 2014 and 2013 are as follows:

		2014		2013
Acquisitions of properties:				
Proved	$	-	$	1,380,000
Unproved		-		-
Exploration and dry hole costs		706,904		900,255
Development		12,927,757		29,790,284
	$	13,634,661	$	32,070,539

The following table sets forth the consolidated results of operations for the years ended December 31, 2014 and 2013:

		2014		2013
Oil and gas revenues	$	52,325,716	$	68,696,055
Lease operating expense		(24,631,620)		(21,685,103)
Workover expense		(4,537,031)		(2,475,541)
Exploration expense		(706,904)		(900,255)
Loss on plugging and abandonment		-		(701,241)
Depreciation, depletion and amortization		(17,853,499)		(17,269,349)
Impairment expense		(107,774,206)		(2,179,075)
Accretion expense		(1,793,865)		(2,552,381)
Gain on revision of asset retirement obligations		75,178		564,719
Severance taxes		(3,649,814)		(7,274,808)
Income before income taxes		(108,546,045)		14,223,021
Income tax benefit (provision)		(189,855)		(8,630,456)
Results of operations for oil and gas producing activities (excluding Corporate overhead and financing costs)	$	(108,735,900)	$	5,592,565

Proved Oil and Gas Reserves

Proved oil and gas reserves for the Company s Louisiana properties were estimated by independent petroleum engineers. Proved reserves for the Company s Gulf of Mexico properties were estimated internally. The reserves were based on the following assumptions:

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Future revenues were based on an unweighted 12-month average of the first-day-of-the-month price held constant throughout the life of the properties.

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Production and development costs were computed using year-end costs assuming no change in present economic conditions.

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Future net cash flows were discounted at an annual rate of 10%.

Reserve estimates are inherently imprecise and these estimates are expected to change as future information becomes available.

The following summarizes our estimated total net proved reserves for the years in the two-year period ended December 31, 2014:

	Gas (Mcf)	Oil (Bbls)	Boe
For the year ended December 31, 2013			
Beginning of year	52,918,300	8,406,600	17,226,317
Acquisition of reserves	8,834,500	1,268,000	2,740,417
Discoveries and extensions	3,011,500	261,200	763,116
Improved recovery	-	-	-
Revisions	(15,569,000)	(92,900)	(2,687,733)
Production	(1,198,800)	(603,600)	(803,400)
End of year	47,996,500	9,239,300	17,238,717
Proved developed reserves			
Beginning of year	9,159,500	2,809,200	4,335,783
End of year	6,880,800	3,245,700	4,392,500
For the year ended December 31, 2014			
Beginning of year	47,996,500	9,239,300	17,238,717
Acquisition of reserves	-	-	-
Discoveries and extensions	-	-	-
Improved recovery	-	-	-
Revisions	(20,467,200)	(2,935,300)	(6,346,500)
Production	(950,100)	(511,700)	(670,050)
End of year	26,579,200	5,792,300	10,222,167
Proved developed reserves			
Beginning of year	6,880,800	3,245,700	4,392,500
End of year	5,204,700	2,898,500	3,765,950

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

The following information was developed utilizing procedures prescribed by Accounting Standards Codification 932-235 (ASC 932-235), *Disclosures about Oil and Gas Producing Activities.* The information is based on estimates prepared by independent petroleum engineers. The standardized measure of discounted future net cash flows should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

In reviewing the information that follows, we believe that the following factors should be taken into account:

future costs and sales prices will probably differ from those required to be used in these calculations;

actual production rates for future periods may vary significantly from the rates assumed in the calculations;

a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and gas revenues; and

future net revenues may be subject to different rates of income taxation.

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices applicable to our reserves to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by ASC 932-235.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows:

(dollars in thousands)		**2014**		**2013**
Future cash inflows	$	704,959	$	1,213,823
Future production costs		(242,110)		(297,786)
Future development costs		(167,409)		(255,309)
Future net cash flows before income taxes		295,440		660,728
Future income tax expense		(35,150)		(181,935)
Future net cash flows before 10% discount		260,290		478,793
10% annual discount for estimating timing of cash flows		(71,495)		(178,003)
Standardized measure of discounted future net cash flows	$	188,795	$	300,790

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves:

(dollars in thousands)		**2014**		**2013**
Beginning of year	$	300,790	$	292,685
Sales of oil and gas produced, net of production costs		(19,507)		(37,261)
Net change in prices and production costs		(66,042)		33,720
Extension, discoveries, and improved recovery, less related costs		-		18,639
Development costs incurred during the year		2,938		8,230
Net change in estimated future development costs		5,194		13,418
Revisions of previous quantity estimates		(209,654)		(87,642)
Net change from acquisitions of minerals in place		-		37,224
Net change in income taxes		89,473		4,235
Accretion of discount		41,075		40,688
Changes in timing and other		44,528		(23,146)
End of year	$	188,795	$	300,790

NOTE 14. SUBSEQUENT EVENTS

Forbearance Agreements

On January 30, 2015, the Company, along with its subsidiaries, Lobo Operating, Inc., Lobo Resources, Inc., Harvest Oil & Gas, LLC and The Harvest Group, LLC entered into a forbearance agreement (the First Lien Forbearance Agreement) with the holders (the First Lien Lenders) of certain notes (the First Lien Notes) issued under that certain Indenture dated as of November 22, 2013 (the First Lien Indenture), by and among the Company and The Bank of New York Mellon Trust Company, N.A., as trustee (the First Lien Trustee). Also on January 30, 2015, the Company entered into a forbearance agreement (the Second Lien Forbearance Agreement) with the holders (the Second Lien Lenders) of seventy-five percent (75%) or more in principal amount of the notes (the Second Lien Notes) issued under that certain Indenture dated as of July 12, 2011 (as supplemented or amended, the Second Lien Indenture), by and among the Company and The Bank of New York Mellon Trust Company, N.A., as trustee (the Second Lien Trustee).

The First Lien Forbearance Agreement and the Second Lien Forbearance Agreement were entered into following (i) the Company s failure to pay to the First Lien Lenders an interest installment in the amount of $1.3 million scheduled for payment on December 31, 2014, and constituting a default if not paid by January 30, 2015 (the Anticipated First Lien Default), and (ii) the Company s failure to pay to the Second Lien Lenders an interest installment in the amount of $7.9 million scheduled for payment on January 1, 2015, and constituting a default if not paid by February 2, 2015 (the Anticipated Second Lien Default, and, together with the Anticipated First Lien Default, the Specified Defaults).

The Company has received confirmation from the First Lien Lenders that they hold more than 75% of the principal amount of the outstanding Second Lien Notes and have each agreed, during the Forbearance Period (as defined below), not to provide any direction to the Second Lien Trustee or to take any steps to enforce any rights of the Second Lien Trustee or the holders of Second Lien Notes occasioned by the failure of the Company to make the January 1, 2015 interest payment.

Pursuant to the First Lien Forbearance Agreement, the First Lien Lenders have agreed to forbear, until the earlier of March 16, 2015 or the occurrence of certain defaults defined in the First Lien Forbearance Agreement (the Forbearance Period), from exercising certain of their default-related rights and remedies against the Company with respect to the Specified Defaults in order to permit the Company an opportunity to effectuate a restructuring/refinancing or implement operational improvements.

Under the terms of the First Lien Forbearance Agreement, among other things, the Company agreed to (i) pay, by February 2, 2015, the December 31, 2014 interest payment owing to the First Lien Lenders, with interest at the default rate, in the amount of $1,378,650; (ii) pay expenses incurred by the First Lien Lenders in connection with the Forbearance Agreement, including paying a retainer to counsel for the First Lien Lenders; (iii) retain, by March 2, 2015, a financial advisor acceptable to the First Lien Lenders on terms acceptable to the First Lien Lenders; (iv) deliver to the First Lien Lenders a 6-week operating budget in form and methodology acceptable to the First Lien Lenders and to abide by that budget within permitted variances; (v) deliver to the First Lien Lenders, not later than March 2, 2015, certain financial, operating and other information and, not later than March 15, 2015, a two year business plan and 2015 budget; and (vi) cause its officers, financial advisors, investment bankers and others to furnish information reasonably requested by the First Lien Lenders.

Any breach by the Company of any covenant in the First Lien Forbearance Agreement, or the commencement of any bankruptcy, insolvency or creditor relief proceedings by or with respect to the Company, will constitute an event of default under the First Lien Forbearance Agreement.

Pursuant to the Second Lien Forbearance Agreement, the Second Lien Lenders have agreed to forbear, during the Forbearance Period, from exercising certain of their default-related rights and remedies against the Company with respect to the Specified Defaults in order to permit the Company an opportunity to effectuate a restructuring/refinancing or implement operational improvements. Second Lien Forbearance Agreement is substantially identical to the First Lien Forbearance Agreement except that the January 1, 2015 interest payment on the First Lien Notes is not required to be made.

On March 16, 2015, the Company entered into amendments to the First Lien Forbearance Agreement and the Second Lien Forbearance Agreement, extending the Forbearance Period to April 30, 2015.

Stock Option Grants

In February 2015, the Company granted stock options to three employees to purchase an aggregate of 75,000 shares of common stock. The options vest over two years and are exercisable for a term of seven years.

Advisory Agreement

In March 2015, pursuant to the terms of the Forbearance Agreements, the Company entered into an engagement letter (the Engagement Letter) with Conway MacKenzie Management Services, LLC (CMS). Pursuant to the Engagement Letter, the Company appointed principals of CMS to the Interim Chief Financial Officer and Strategic Alternatives Officer positions. Those officers are engaged to assist the Company in connection with its efforts to restructure or repay the First Lien Notes and Second Lien Notes. The Company will pay CMS a fee of $50,000 per month for services of the Interim Chief Financial Officer and pay hourly fees for services of other CMS personnel.