SARATOGA RESOURCES, INC.

13001866

To Our Shareholders:

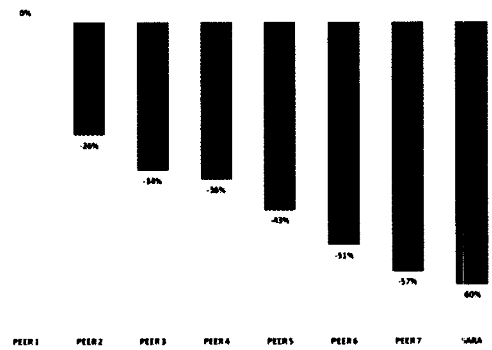
During 2012, Saratoga faced a series of challenges presented by Hurricane Isaac. In spite of the effects of the hurricane, we still managed to generate $1.00 per share in discretionary cash flow and we believe we are significantly undervalued as we exited the year with roughly $9.00 in NAV per share.

Entering the year, our focus was on production growth while continually keeping an eye on opportunities to grow and upgrade our prospect inventory. To that end, and in spite of some major challenges, we were able to grow production as our continuing development program produced an 18% growth rate in production volumes and a resulting 8% increase in oil and gas revenues. We also saw significant progress during 2012 in risk management and asset optimization efforts as we re-instituted our hedging program to reduce our exposure to commodity price risks and re-initiated our field reserve studies to maximize and optimize drilling opportunities.

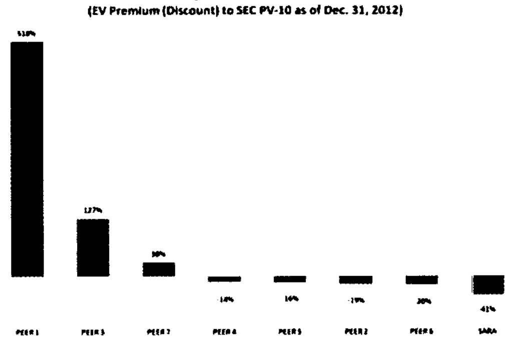
However, the progress we made during 2012 in continuing our development program and upgrading our asset base was overshadowed in many regards by the effects of Hurricane Isaac. The shut-in production, delays in completions and deferral of projects caused by Isaac had a material impact on production, revenue, earnings and cash flow that is reflected in our year end results. Fortunately, our properties are resilient, as evidenced by the relatively minimal damage inflicted by the hurricane, and our dedicated team worked hard in bringing the majority of our production back on line by year-end and in resuming our development program.

Continued Strength in Asset Position: What did not change is the inherent value of our assets in South Louisiana. We have a high value asset base with approximately $9 per share of Net Asset Value in proved reserves and a deep inventory of relatively low risk PDNP and PUD conversion opportunities. As of year-end 2012, we were trading at a 60% discount to NAV/share, a significantly higher discount than our peer group. Furthermore, our enterprise value was at a 41% discount to proved SEC PV10, more than twice that of our nearest peer company.

Peer Comparison[1] of Price to NAV/Share
(Stock Premium (Discount) to NAV/Share as of Dec. 31, 2012)



Peer Comparison[1] of EV/PV-10
(EV Premium (Discount) to SEC PV-10 as of Dec. 31, 2012)



7500 San Felipe, Suite 675 • Houston, Texas 77063 • Tel 713-458-1560 • Fax 713-458-1561 • www.saratogaresources.net

SARATOGA RESOURCES, INC.

We continue to believe that the quality and location of our properties reduce our development risk and promote operating efficiencies as well as serving as a platform for accretive acquisitions. We are also positioned to participate in what we believe is an exciting ultra-deep trend with multiple exploratory targets already identified in that trend.

We control over 32,000 acres, all in state and parish leases in shallow water of south Louisiana, with virtually all of our acreage held by production to all depths. 25% or our proved reserves are proved developed and 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.

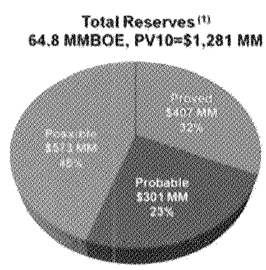
With our first quarter 2013 apparent high bids on four blocks in the shallow Gulf of Mexico shelf, we are positioned to add to our large acreage position and drilling inventory. If ultimately approved, based on our internal analysis, we expect these leases to be immediately accretive and to add proved reserves at a favorable price.

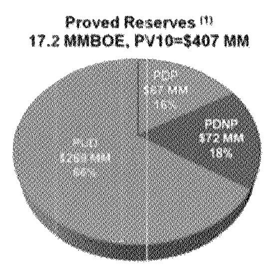
Highlights of the 2013 high bid prospects include:

- 4 blocks covering 19,814 acres in shallow water depths between 13 and 77 feet.
- Up to 51.2 million gross BOE of 3P reserves with 5.4 million gross BOE as potential PUD's.

Developing Our Reserves: Our 2012 development program produced a 100% success rate with the drilling of three successful development wells, the Jupiter, North Tiger and Mesa Verde wells and our Buddy well that was drilled during the year and awaiting completion at year end. Jupiter, North Tiger and Buddy each added reserves and moved proved reserves onto production. Mesa Verde, while successful, produced negative reserve adjustments due to thin sands encountered. It should be noted that Mesa Verde set up a potential side-track well which we believe will allow us to recover lost reserves and also served to strengthen our leasehold position in our Vermilion 16 field which lies in the heart of the shallow water ultra-deep trend which is presently the focus of much attention.

Despite the successes of our accelerated development program, like many other E&P companies, we took a haircut on our reserves during 2012. Our proved reserves as of December 31, 2012 stood at 8.4 million barrels of oil and 52.9 billion cubic feet of natural gas for a total of 17.23 million BOE, down 9.2% from 2011. Crude oil represents 49% of our total proved reserves, significantly up from 42% of the mix at year end 2011.





SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2012

☐ **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.)*

7500 San Felipe, Suite 675, Houston, Texas 77063
(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 ☐ No ☒

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 ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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 ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2012, based on the closing sales price of the registrant's common stock on that date, was approximately $79.1 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 ☒ No ☐

The number of shares of the registrant's common stock, $0.001 par value, outstanding as of March 1, 2013 was 30,911,601

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2013 Annual Meeting are incorporated by reference into Part III of this Report.

TABLE OF CONTENTS

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 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.

"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 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 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. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable from known reservoirs under current economic and operating conditions, operating methods, and government regulations.

"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, 2012, our properties were located exclusively in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana. Those properties spanned 12 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. Our properties, the majority of which were acquired in July 2008, cover an estimated 32,027 gross/net acres and substantially all are held by production ("HBP") without near-term lease expirations. Most of our properties offer multiple stacked reservoir objectives with substantial behind pipe potential. We continually seek to enhance our acreage position through leasing and evaluation of opportunistic acquisitions both within the transition zone and beyond. To that end, during the first quarter of 2013, we bid on, and were the apparent high bidder with respect to, four leases totaling 19,814 acres in the Central Gulf of Mexico and, subject to review of the bids and final award of the leases by the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), will add to our property holdings in the Gulf of Mexico shelf.

As of December 31, 2012, our total proved reserves were 17.2 MMBoe, consisting of 8.4 MMBbls of oil and 52.9 Bcf of natural gas. The PV-10 of our proved reserves at December 31, 2012 was $407 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $443 million. Additionally, we had probable reserves of 13.3 MMBoe, consisting of 5.9 MMBbls of oil and 45.0 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities.

During 2012, we produced 1,116 MBoe, of which 61% was oil. As of December 31, 2012, our development opportunities included 58 proved behind pipe and shut-in opportunities in 7 fields, 89 proved undeveloped opportunities within 28 proposed wells in 4 fields and 31 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2012, we had 38 probable undeveloped opportunities within 26 proposed wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 87 possible undeveloped opportunities within 29 wells in 3 fields. During the year ended December 31, 2012, we successfully completed 3 development wells, 2 of which were completed as dual completions, 12 recompletions and 16 workovers. At year end, we had one additional developmental well that had finished drilling and logging and was awaiting completion. That well was successfully completed during the first quarter of 2013.

We operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Chapter 11 Reorganization." As a result of declaring bankruptcy and the absence of availability under our credit facilities, we operated in a liquidity constrained environment from early 2009 through March 2011.

During the year ended December 31, 2012, we raised approximately $23.3 million of equity and $25.0 million of debt financing.

Our principal and administrative offices are located at 7500 San Felipe, Suite 675, 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 Apache Corporation, Energy XXI (Bermuda) Limited, EPL Oil & Gas, Inc., Hilcorp Energy Company, McMoRan Exploration Co. and Swift Energy Company. 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, which are relatively low risk.

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, Vermilion 16 Field and 10 other established fields on state and parish leases of south Louisiana. 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 exclusively in shallow state waters, we are not currently subject to the regulations of the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") applicable to federal leases and 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. While the expected addition of holdings on the Gulf of Mexico Shelf will be subject to BOEMRE regulation, and in deeper waters, the new acreage shares the geographic focus and many geological characteristics with our existing holdings and is in relatively shallow waters which we believe will allow us to continue to leverage our knowledge base and to attract partners and operators experienced in operations in such environments.

Extensive Workover and Drilling Inventory. At December 31, 2012, we controlled approximately 32,027 gross/net acres that were largely HBP. Approximately 88% 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, 2012, our development opportunities included 58 proved behind pipe and shut-in opportunities in 7 fields, 89 proved undeveloped opportunities within 28 proposed wells in 4 fields and 31 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2012, we had 38 probable undeveloped opportunities within 26 proposed wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 87 possible undeveloped opportunities within 29 proposed wells in 3 fields. Based on our initial internal analysis, we anticipate that the addition of acreage from our first quarter 2013 lease bids will add to our proved reserves and our development opportunities.

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 98% of the wells that comprise our PV-10 as of December 31, 2012. 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 200 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:

Capitalize on Added Liquidity to Expand and Accelerate Development. Since April 2011, we have raised approximately $58.0 million of new equity financing and $152.5 million of new debt financing and retired $145.2 million of debt and $12.1 million of letter of credit obligations. As a result of this added liquidity, we have significantly expanded our capital spending from the approximately $17.0 million we spent in 2009 and 2010 combined to $25.9 million in 2011 and to $59.8 million in 2012. During 2012, we deployed that added liquidity to drill 4 wells, 3 successful and 1 in progress, for total capital expenditures of $39.6 million with combined initial production rates from those wells of 1,779 net Boepd. In addition, we successfully completed 11 of 12 recompletions during 2012 for total expenditures of $16.6 million and successfully completed 16 workovers during 2012 for total expenditures of $3.8 million. During 2011 and 2012, combined, we spent approximately $9.1 million on new and upgraded infrastructure to support our operations and planned growth. We intend to continue to utilize our added liquidity to upgrade infrastructure as needed and to strategically develop our remaining inventory of prospects.

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, subject to final award of our high bid leases in the Central Gulf of Mexico, through participation via farm-outs or promoted deals in development of our acreage on the Gulf of Mexico shelf.. As of December 31, 2012, our plans are to drill five to six development wells in 2013 and annually thereafter and to carry out 15 to 20 recompletions, through-tubing plugbacks and workovers during 2013. Development work is expected to be spread over several fields with annual capital expenditures associated with these projects expected to be in excess of $40 million and finding and development costs, based on historical performance, expected to be approximately $15 to $20 per Boe. 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 98% of the wells that comprise our proved reserves as of December 31, 2012, 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 on which we were the apparent high bidder, 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, 2012, we either owned or held licenses for 3-D seismic data covering over 450 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.

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, 2012:

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)
Grand Bay	7,241	64%	$ 210,373	17,270	70-79%	51	16.0
Vermilion 16	6,069	27%	$ 88,780	4,095	75-83%	1	*
Main Pass 46	1,539	31%	$ 23,583	1,662	74-79%	4	3.4
Other	2,377	70%	$ 84,147	9,000	75%	30	4.1
All Properties	17,226	49%	$ 406,883	32,027	75%	86	11.4

* Not meaningful

(1) PV-10 is a non-GAAP financial measure as defined by the SEC. Based on unweighted average benchmark prices as of the first of each month during 2012 of $94.71 per Bbl and $2.76 per MMBtu and before future income taxes. The average realized price after applying differential to unweighted average benchmark prices was $110.06 per Bbl and $3.36 per Mcf.

(2) Calculated by dividing total net proved reserves by current net production for December 2012.

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 Corp. discovered the field in 1938. We are the operator of all of the Grand Bay Field with 100% working interest and an average 70% to 79% net revenue interest. Our leases in the Grand Bay Field, which are all HBP, cover an estimated 17,270 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 67 active wellbores, 46 proved developed nonproducing opportunities and 68 proved undeveloped opportunities in 18 proposed drilling locations within the field. There are also 19 probable developed nonproducing, 27 probable undeveloped opportunities in 20 proposed drilling locations, 12 possible developed nonproducing and 47 possible undeveloped opportunities in 18 proposed drilling locations within the field. We have undertaken a comprehensive full field study approach at Grand Bay Field that is still ongoing. The emphasis of the most recent field study is a detailed mapping of each of the major producing sands, integrating well data and recently reprocessed 3-D data, looking at original reservoir conditions and backing out historical production to see what remains to be developed with infill wells. Saratoga is looking for horizontal well candidates since there has only been one horizontal completion to date, the GPLD A-183 well, yet that was one of the best producers in the field. Another important part of the study is the geopressured sequence incorporating the Cib Carst (25 sand), Uvig3 (30 sand) and Tex W (43 sand) reservoirs, which has been largely unexplored to date.

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 and 2012. We expect to use this dataset to better locate proposed development wells and deep oil and gas targets below existing production.

During 2012, we drilled the SL 195QQ-202 "Jupiter" well in Grand Bay Field and completed it as a dual completion. The Jupiter well was spud in July 2012 and reached total depth of 9,688 feet MD/TVD. The well encountered 104 feet of net pay in 15 sands between 5,516-9,042 feet and was completed in the 15 sand in early August 2012. The well tested on August 14, 2012 at a gross rate of 245 BOPD and 650 MCFPD, or net 254 BOEPD, on 15/64" choke with FTP of 860 psi.

During 2012, we also drilled the SL 195QQ-209 "Buddy" well in Grand Bay Field, but had not completed it by year-end. The Buddy well was drilled to a total depth of 6,820 feet MD/TVD and was successfully completed, in early 2013, in the 3A sand. Flow testing of the Buddy well demonstrated an IP rate of 208 net BOEPD. Flowing tubing pressure was 580 pounds per square inch on a 19/64" choke.

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.

Vermilion 16 Field. The Vermilion 16 Field is located in the transitional coastline in a protected in-bay environment on state leases offshore Vermilion Parish, approximately 40 miles south of Lafayette, Louisiana. It is situated in approximately 12 feet of water, 0.5 miles offshore in the Gulf of Mexico. We are the operator with a 100% working interest and a net revenue interest ranging from 75% to 83%. The seven existing state leases cover an estimated 4,095 gross/net acres, of which 3,573 net acres are HBP.

The field is a four-way rollover anticline on the downthrown side of a down-to-the-south fault. There are multiple stacked reservoirs within the field. There are 6 wellbores associated with this field and 4 proved undeveloped drilling locations within the field. We licensed 25 square miles of 3D seismic data in 2008, which we expect to use to better locate proposed development wells.

During 2012, we drilled and completed the SL 3763-14 "Mesa Verde" well in 2012. The Mesa Verde well was spud on May 14, 2012 and reached a total depth of 16,258 feet MD/ TVD on July 23, 2012. The well encountered up to 15 potentially productive intervals, including the Marg A, LF, Rob 54 and Amph B sands between 11,333-15,890 feet and was completed in the LF-H sand in October 2012. The well tested on October 12, 2012 at a gross rate of 190 BOPD, 4,066 MCFPD, or net 685 BOEPD, on a 14/64" choke with flowing tubing pressure ("FTP") of 4,300 psi.

Facilities include a central platform and the 6 wellbores associated with the field.

During 2012, pending the results of several high profile ultra-deep wells in the area, we continued to evaluate joint venture and other opportunities to explore ultra-deep prospects in Vermilion 16 Field and drilled our Mesa Verde well which is expected to preserve all rights in the field, including ultra-deep rights that have been the subject of joint venture discussions with McMoran Exploration.

Main Pass 46 Field. The Main Pass 46 Field is located in the transitional coastline in a protected in-bay environment on state leases offshore Plaquemines Parish, approximately 80 miles south-southeast of New Orleans, Louisiana. The field is situated in approximately six feet of water, immediately north of Grand Bay Field. We are the operator with a 100% working interest and a net revenue interest ranging from 74% to 79%. The four existing state leases cover an estimated 1,662 gross/net acres and are all HBP.

The field is a faulted anticlinal structure with outlying stratigraphic traps. There are multiple stacked reservoirs within the field. The Main Pass 46 Field is partly covered by the 90 square mile proprietary 3-D Grand Bay survey.

Facilities include a central platform and the 5 active wellbores associated with the field. All of the 11 proved undeveloped opportunities in 3 proposed new wellbores are located within Grand Bay State Lease 195.

Other Fields. We hold interests in 9 other fields, all of which are located in shallow waters on state leases in Plaquemines, St. Bernard and St. Mary parishes of southern Louisiana, with 100% working interests 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 9,000 gross/net acres.

Among the other fields in which we hold interests are the Main Pass and Breton Sound fields, which are a series of stratigraphic trap-type fields in the Middle Miocene trend that were discovered with 3-D seismic technology. The reservoir drive mechanisms are water drive and combination water drive/pressure depletion. We have licensed the entire SEI Breton Sound 3-D survey that covers approximately 400 square miles.

During 2012, we drilled and completed the SL 20433-1 "North Tiger" well in Breton Sound Block 19. The North Tiger well was spud in July 2012 and reached total depth of 9,532 feet MD/9,300 feet TVD. The well encountered 59 feet of net pay in 6 sands and was completed as a dual producer in October 2012. The well tested on October 15, 2012 at a gross rate of 517 BOPD and 1,457 MCFPD on a 14/64" choke with FTP of 1,900 psi from the 7,100' sand in the short string and 258 BOPD and 351 MCFPD on a 17/64" choke with FTP of 580 psi from the Cib Carst sand in the long string, or combined net 840 BOEPD.

Gulf of Mexico Shelf Acreage. In March 2013, we bid on, and were the apparent high bidder relative to, four leases 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. Final award of the leases is subject to BOEMRE review.

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 six platform facilities plus 36 active producing wellbores associated with these fields, including ten saltwater disposal wells. Facilities at the Grand Bay Field include four tank batteries, a compressor station, various flowlines and a bunk house. In addition to serving our wells and improving field economics, we generate processing and production handling revenues from third-party customers.

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2012, 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 carryforwards 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.

	Reserves(1)		
Reserve category	**Oil (MBbls)**	**Natural Gas (MMcf)**	**Total(2) (MBoe)**
Proved			
Developed			
Producing	1,367	3,868	2,012
Shut-in	162	1,076	341
Behind Pipe	1,280	4,216	1,983
Total Proved Developed	2,809	9,160	4,336
Undeveloped	5,597	43,759	12,890
Total Proved	8,406	52,919	17,226
Probable(3)			
Developed	663	5,047	1,504
Undeveloped	5,187	39,934	11,843
Possible(3)			
Developed and Undeveloped	5,851	117,257	25,394
PV-10(1) (in thousands)			$ 406,883
Standardized Measure(4) (in thousands)			$ 292,685

(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, 2012. 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, 2012 which were $94.71 per Bbl and $2.76 per MMBtu. The prices utilized for purposes of estimating our proved reserves were $110.06 per Bbl and $3.36 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. We believe that using the 10-year average NYMEX strip prices yields a better indication of the likely economic producibility of proved reserves than the trailing average 12-month price required by SEC reserves rules. 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 2012 12-month average prices reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2012.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)[1]	PV-10 (in thousands)
SEC Case	8,406	52,919	17,226	$406,883
NYMEX Strip Price Case[2]	8,395	53,480	17,308	$442,580

(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, 2012, as benchmark prices for 2012 through 2018, and continued to use the 2018 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 $85.92 per barrel of oil and $4.88 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.

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, supplemented by consultants, who work closely with Collarini Associates 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 Collarini Associates periodically throughout the year to discuss the assumptions and methods used in the reserve estimation process. We provide historical information to Collarini Associates for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. The activities of our staff are led and overseen by our President, a degreed petroleum geologist/geophysicist with over 30 years of technical experience involving petroleum reserve assessment and estimation and geoscience-based evaluation. He is assisted by our Asset Evaluation Manager, who has over 25 years of technical experience in petroleum engineering and reservoir evaluation and analysis. Together, these individuals direct the activities of our engineering and geosciences staff who coordinate with our accounting and other departments to provide the appropriate data to Collarini Associates in support of the reserve estimation process and to assure that information derived from Collarini Associates' 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 was prepared under the direction of Collarini Associates' President and Engineering Manager. Collarini Associates' Engineering Manager 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.

Collarini 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

As of December 31, 2012, our proved undeveloped reserves totaled 5.6 MMBbls of oil and 43.8 Bcf of natural gas, for a total of 12.9 MMBoe compared to 5.4 MMBbls of oil and 55.9 Bcf of natural gas, for a total of 14.7 MMBoe as of December 31, 2011. The change in our proved undeveloped reserves was attributable to a loss of reserves (2,637 MBoe) associated with the Vermilion 16 field following the drilling of the Mesa Verde well, a further loss of reserves (315 Mboe) due to economic limit revisions relating to prices and conversion of proved undeveloped reserves to proved developed (approximately 888 MBoe), partially offset by new additions due to field studies in Breton Sound 32 and Grand Bay fields (950 MBoe), and due to successful development drilling at Breton Sound 18 and Grand Bay fields (517 MBoe).

All of our proved undeveloped reserves at December 31, 2012 were associated with our Louisiana properties.

We incurred costs relating to the development of proved undeveloped reserves of $39.8 million and $11.3 million during 2012 and 2011, respectively.

All proved undeveloped locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2017. 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, 2012.

	2010	2011	2012
Net Production:			
Oil (Bbl)	550,000	605,900	676,400
Natural gas (Mcf)	1,882,800	2,038,000	2,639,500
Combined volumes (Boe)	863,800	945,567	1,116,317
Average sales price per Boe	$ 61.05	$ 80.54	$ 73.93
Average production cost per Boe(1)	$ 18.44	$ 20.93	$ 20.74

(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. We have had a 100% success rate in developmental drilling over the past three years and an 86% success rate on all drilling over the last three years.

	2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	0	0	0	0	0	0
Unproductive	0	0	1	1	0	0
Total	0	0	1	1	0	0
Developmental Wells:						
Productive	1	1	2	2	3	3
Unproductive	0	0	0	0	0	0
Total	1	1	2	2	3	3
Success Ratio (1)	100%	100%	67%	67%	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 2012 we successfully completed 11 out of 12 recompletion and 16 workover operations and during 2011 we successfully completed 7 out of 9 recompletion and 25 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, 2012, one well had been drilled and logged, but was awaiting completion. There were no recompletion or workover operations being conducted at year end.

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, 2012:

	Gross	Net
Oil wells	92	91
Gas wells	13	13
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, 2012 included 5 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, 2012, all of which is located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana:

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross	Net	Gross	Net	Gross	Net
31,505	31,505	522	522	32,027	32,027

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.

The following table sets forth, as of December 31, 2012, the expiration periods of the gross and net acres that are subject to leases summarized in the above table of undeveloped acreage.

	Undeveloped Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2013	0	0
December 31, 2014	522	522
December 31, 2015	0	0
December 31, 2016	0	0
December 31, 2017 and later	0	0
Total	522	522

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 during the second half of 2011 and 2012, and we anticipate that market conditions should allow us to continue to receive pricing above WTI postings into 2013. At December 31, 2012, we were marketing our crude oil at prices that were averaging approximately $19.08 per bbl above WTI price postings.

Sales of oil and gas production to Shell Trading (US) Company and Shell Energy North America (US), L.P. (collectively "Shell") accounted for 35.5% and 94.0% of our consolidated sales in 2012 and 2011, respectively. In addition, sales of oil and gas production to Plains Marketing and J. P. Morgan Ventures Energy Corp. accounted for 33.4% and 12.3%, respectively, of our consolidated sales in 2012. 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, 2012, we had in place the following hedging contracts:

Instrument	Beginning Date	Ending Date	Fixed Price	Total Bbls
Swap	January 2013	March 2013	$ 108.00	67,500
Swap	January 2013	March 2013	106.00	22,500
Swap	January 2013	March 2013	$ 108.50	45,000
				135,000

Shell Trading (US) Company is the counterparty to each of our present forward physical contracts and fixed price swap contracts. 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, 2012, we had 31 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.

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.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states on shore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

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.

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. For example, the NYMEX crude oil spot price per barrel for the period between January 1, 2012 and December 31, 2012 ranged from a high of $110.55 to a low of $77.28 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2012 to December 31, 2012 ranged from a high of $3.93 to a low of $1.90. 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.

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, 2012 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.

As of December 31, 2012, approximately 75% of our total proved reserves were undeveloped and approximately 13% 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. While we were able to substantially increase our drilling and development budget in 2011 and 2012 using cash flow and funds provided by debt and equity offerings, at December 31, 2012, we lacked a revolving credit facility and, accordingly, are dependent upon operating cash flow and 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 would be 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. 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 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 additional partners to absorb a substantial portion of our share of such exploration costs. To that end, we have entered into 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, 2012, entered into a definitive agreement with any prospective partner to fund or participate in the exploration of our ultra-deep prospects. 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 expected to be some of the deepest wells ever drilled in the world and are subject to very high pressures and temperatures. The drilling, logging and completion techniques are 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 final approval of leases by the BOEMRE and participation of partners in the financing and development of those prospects.

We were apparent high bidder in four leases totaling 19,814 acres in the shallow Gulf of Mexico shelf. Finalization of such leases, and our rights to participate in the development of such prospects, is subject to final approval of the leases by the

BOEMRE. Further, we have no history of developing and operating properties subject to BOEMRE 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.

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 Deep Water 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 98% of our proved reserves, but do not expect to operate any wells that may be drilled on the Gulf of Mexico prospects on which we were high bidder in early 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, including 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. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our vendors', customers' and counterparties' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing 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.

Three customers accounted for approximately 81% of our total oil and natural gas revenues during the year ended December 31, 2012. 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.

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, 2012, we had total indebtedness of $152.5 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.

We and our subsidiaries may be able to incur substantially more debt. This could further increase our leverage and attendant risks.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of the indentures governing our senior notes do not fully prohibit us or our subsidiaries from doing so. We continue to evaluate the establishment of a revolving credit arrangement under which would be able to borrow additional amounts. If new debt or liabilities are added to our current debt level, the related risks that we now face could increase.

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 indenture governing our senior notes contains 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.

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 and 2012. 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, 2012, we lacked a revolving credit facility and had no existing commitments to provide financing if needed 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 deterioration of the capital and credit markets.

The recent credit crisis and related turmoil in the global financial systems had an impact on our business and our financial condition, and we may face challenges if economic and financial market conditions 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. A recurrence of the economic crisis could further reduce the demand for oil and natural gas and put downward pressure on the prices for oil and natural gas.

The recent credit crisis 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. Also, as a result of concerns about the general stability of financial markets and the solvency of specific counterparties, the cost of obtaining money from the credit markets increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity or on terms similar to existing debt or at all, or, in some cases, ceased to provide any new funding. A return of these conditions could materially and adversely affect our company.

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.

The Deepwater Horizon explosion and ensuing oil spill could have broad adverse consequences affecting our operations in the Gulf Coast region, some of which may be unforeseeable.

The April 2010 explosion and sinking of the Deepwater Horizon drilling rig and resulting oil spill has created uncertainties about the impact on our future operations in the Gulf Coast region. While we do not presently operate any properties in the deep water of the Gulf of Mexico, increased regulation in a number of areas could disrupt, delay or prohibit future drilling programs and ultimately impact the fair value of our properties even where those properties are not in federal waters and should we elect in the future to participate in properties in federal waters.

In addition to the drilling restrictions, new safety measures and permitting requirements already issued, there have been numerous additional proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and oil spill that could affect our operations and cause us to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs, and, further, could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf Coast region more difficult, more time consuming, and more costly.

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. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half 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.

Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law by President Obama on July 21, 2010 and requires the Commodities Futures Trading Commission ("CFTC"), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. 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 also 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.

The Budget for Fiscal Year 2013 sent to Congress by President Obama on February 13, 2012, contains recommendations that, if enacted into law, 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 at shareholders meetings, 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

Ad Valorem Tax Litigation – Plaquemines Parish, Louisiana

In December 2009, the Parish of Plaquemines, State of Louisiana, filed supplemental assessments against multiple oil and gas companies, including Saratoga, for allegedly omitting or undervaluing oil producing assets on the annual self-reporting tax renditions used to calculate ad valorem taxes. In short, the difference between what was reported by the oil and gas companies and what the assessor taxed boiled down to how depreciation of the oil and gas related equipment was calculated and how certain equipment was classified. The amount alleged to be due by Saratoga for the years 2006, 2007, and 2008 is $1.3 million in Parish taxes. Also at issue are the increased assessment valuations for the years 2009, 2010, and 2011 brought by the Parish under the same theory. Saratoga is contesting the additional tax assessments in an action styled *Aviva America, Inc., The Harvest Group, LLC, Harvest Oil & Gas, LLC, Saratoga Resources, Inc., Lobo Operating, Inc. and Lobo Resources, Inc. v. Robert R. Gravolet, In His Capacity as Assessor for Plaquemines Parish, Louisiana*, 25th Judicial District Court for the Parish of Plaquemines, and, as to certain issues relating to such claim, a number of administrative proceedings before the Louisiana Tax Commission are also being fought. We believe the additional assessment is in error and intend to vigorously defend this action.

Y&S Marine v. The Harvest Group, LLC

In July 2010, Y&S Marine, Inc. filed suit against the Company's subsidiary, The Harvest Group, LLC, in the U.S. District Court for the Eastern District of Louisiana, styled *In re: Y&S Marine, Inc. as Owner and Operator of the M/V Sun Fighter*. The suit arose when a vessel operated by Y&S allided (the running of one vessel against another) with the well-head of The Harvest Group, LLC's Well No. 22, located on Breton Sound 32 in Louisiana territorial waters. In the suit, Y&S is seeking to limit its liability to The Harvest Group, LLC to the value of the vessel, which Y&S claims is approximately $240,000. The Harvest Group, LLC filed an answer and counterclaim in the limitation proceeding against Y&S seeking losses sustained as a result of the allision. The Harvest Group, LLC is seeking damages for all of its uninsured losses, which include approximately $515,000 plus lost production revenue resulting from the shut in of the No. 22 Well. The amount of the lost production has not yet been determined. The Harvest Group, LLC, along with its subrogation insurer St. Paul Surplus Line Insurance Company, filed motions for summary judgment against Y&S on March 6, 2012 seeking the dismissal of certain of Y&S affirmative defenses. Y&S filed a cross motion regarding same. A hearing on the cross motions was held in April 2012 and a decision on those motions remains pending.

The Harvest Group, LLC, et al. v. Barry Ray Salsbury, et al.

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 has 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. In addition, certain of the former owners asserted a counterclaim for $0.2 million for improper collection of joint interest billing credits and Professional Oil & Gas Marketing asserted counterclaims against Saratoga for $0.2 million for unpaid fees and reimbursable tax payments. During 2011, Saratoga concluded settlements with Barry Ray Salsbury, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer 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. Litigation is still pending as to the remaining defendants, including Brian Carl Albrecht, Professional Oil and Gas Marketing, and Henry Calongne.

Douglas Joseph v. Moncla Marine Operations, LLC, et al

On October 10, 2012, Douglas Joseph, as plaintiff, filed suit against Saratoga and Moncla Marine Operations ("Moncla") in the U.S. District Court for the Western District of Louisiana, in a suit styled *Douglas Joseph v. Moncla Marine Operations, LLC, et. al.* Plaintiff is an employee of Moncla and, in that capacity, alleges that he was injured when debris was discharged from a well on which he was working striking him in the eye. Plaintiff brought a personal injury claim under the Jones Act and admiralty/maritime law seeking $3 million in damages for loss of past and future wages, pain and suffering, past and future medical expenses and loss of society. The matter has been referred to Saratoga's insurance company which is expected to defend the suit. Saratoga also expects to seek indemnification from Moncla.

We may from time to time be a party to lawsuits incidental to our business. Except as noted above, as of December 31, 2012, 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". Prior to July 20, 2011, our common stock traded on the OTCQB marketplace under the symbol "SROE.PK." 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 2012	Fourth Quarter	$ 5.71	$ 3.15
	Third Quarter	6.26	4.81
	Second Quarter	7.55	5.63
	First Quarter	7.81	5.88
Calendar Year 2011	Fourth Quarter	$ 7.40	$ 4.13
	Third Quarter	6.51	4.06
	Second Quarter	11.00	2.31
	First Quarter	3.50	2.25

At March 1, 2013, the closing price of our common stock on the NYSE MKT was $3.08.

As of March 1, 2013, there were approximately 1,499 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, 2012 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]	320,000	5.34	2,630,000
Equity compensation plans not approved by security holders [2]	464,000	2.50	-
Total	784,000	3.66	2,630,000

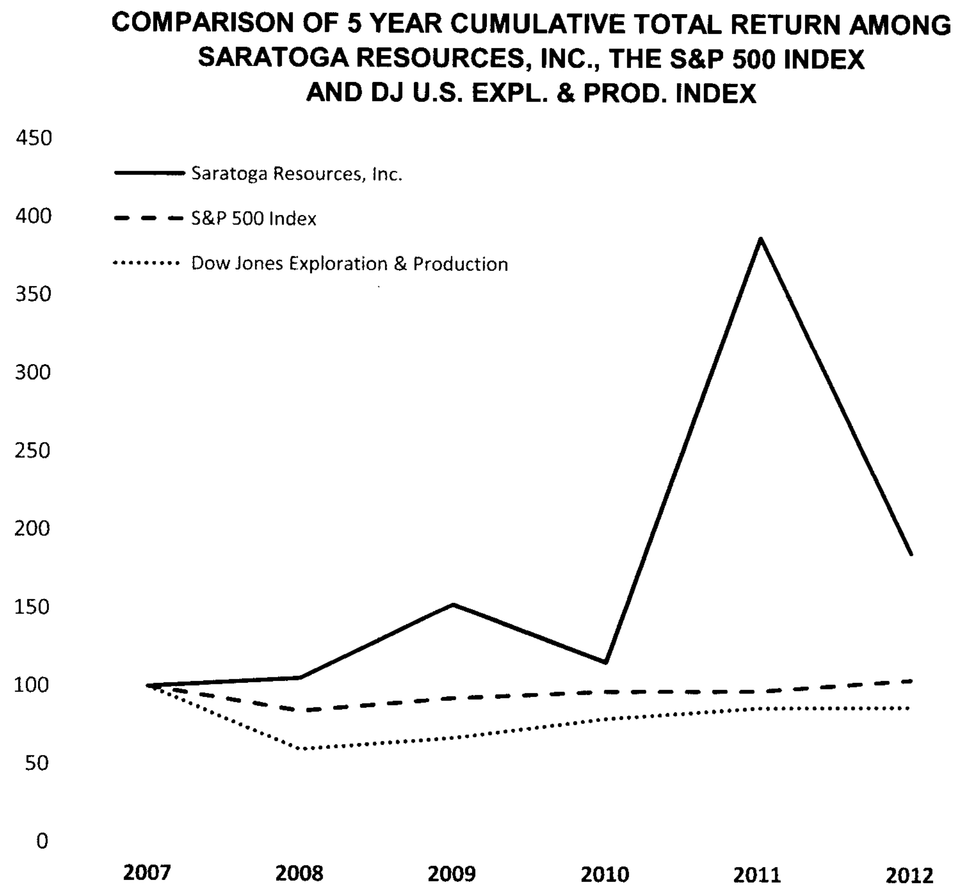
(1) Consists of 3,000,000 shares reserved for issuance under the Saratoga Resources, Inc. 2011 Omnibus Incentive Plan (the "2011 Plan").

(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.

Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following performance graph compares the change in the cumulative total return of Saratoga Resources' common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2012. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2007, and that dividends were reinvested.



	December 31,					
	2007	2008	2009	2010	2011	2012
Saratoga Resources, Inc.	$ 100.0	$ 105.3	$ 152.8	$ 115.9	$ 387.9	$ 185.8
S&P 500 Index	$ 100.0	$ 84.3	$ 92.6	$ 97.2	$ 97.6	$ 104.7
DJ U.S. Expl. & Prod. Index	$ 100.0	$ 59.8	$ 67.3	$ 79.9	$ 86.8	$ 87.4

Item 6. Selected Financial Data

Following is a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2012. Financial information for the year ended December 31, 2008 is pro forma combined information reflecting the operations of Harvest Oil & Gas, LLC and The Harvest Group, LLC for the period January 1, 2008 through July 14, 2008, on which date the company acquired the Harvest companies, and consolidated financial information of the company and its subsidiaries, including the Harvest companies, from July 15, 2008 to December 31, 2008. The financial information for 2008 is not necessarily indicative of the results that would have been attained had the acquisition of the Harvest companies occurred on or prior to January 1, 2008. This information is derived from our Financial Statements and the notes thereto. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2012	2011	2010	2009	2008
			(in thousands)		
Statement of Operations Data:					
Revenues:					
Oil and gas revenues	$ 82,529	$ 76,159	$ 52,734	$ 47,391	$ 68,900
Oil and gas hedging	72	—	—	—	—
Other revenues	1,411	4,775	2,284	1,835	2,875
Total revenues	84,012	80,934	55,018	49,226	71,775
Operating Expenses:					
Lease operating expense	19,317	17,124	14,106	17,761	26,995
Workover expense	3,828	2,667	2,154	2,112	1,028
Exploration expense	547	596	1,590	1,146	—
Loss on plugging and abandonment	2,469	393	—	—	—
Dry hole costs	93	3,913	—	—	—
Gain on revision of asset retirement obligations	(245)	(304)	—	—	—
Gain on purchase price adjustment	—	(1,427)	—	—	—
Depreciation, depletion and amortization	27,408	15,591	16,002	14,578	7,846
Accretion expense	1,510	1,673	1,668	1,439	1,371
Loss on settlement of accounts payable	—	—	991	—	—
General and administrative	8,585	8,704	8,476	6,064	7,858
Impairment expense	402	642	—	—	1,693
Severance taxes	7,768	6,091	5,215	5,672	8,120
Total operating expenses	71,682	55,663	50,202	48,772	54,911
Operating income (loss)	12,330	25,271	4,816	454	16,864
Other income (expense):					
Commodity derivative income (expense)	—	—	697	(4,030)	20,073
Financing expense	(8)	(837)	—	—	—
Gain on extinguishment of debt	—	7,708	—	—	—
Interest expense, net	(17,619)	(17,699)	(22,470)	(27,482)	(15,207)
Total other income (expense)	(17,627)	(10,828)	(21,773)	(31,512)	4,866
Net income (loss) before reorganization expense and income taxes	(5,297)	14,443	(16,957)	(31,058)	21,730
Reorganization expense	161	436	2,198	5,656	—
Income tax expense (benefit)	(1,750)	(6,839)	286	(9,720)	10,312
Net income (loss)	$ (3,708)	$ 20,846	$ (19,441)	$ (26,994)	$ 11,418
Basic net income (loss) per share	$ (0.13)	$ 0.95	$ (1.14)	$ (1.62)	$ n.m.
Diluted net income (loss) per share	$ (0.13)	$ 0.93	$ (1.14)	$ (1.62)	$ n.m.
Cash dividends paid per share	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Cash Flow Data:					
Cash flow from operating activities	$ 26,059	$ 33,845	$ (1,336)	$ 18,740	$ 25,120
Cash flow from investing activities	(56,289)	(30,472)	(10,209)	(4,357)	(15,890)
Cash flow from financing activities	46,658	8,091	(5,590)	1,514	(4,723)
Balance Sheet Data (at end of period):					
Working capital (deficit)	$ 21,175	$ 8,501	$ 2,643	$ 2,824	$ (10,529)
Property, plant and equipment, net	180,071	142,929	133,834	139,651	147,936
Total assets	254,651	197,762	151,343	173,839	176,413
Long-term debt, less current portion	150,396	125,385	131,200	108,811	108,717
Total stockholders' equity	62,463	41,871	(4,111)	7,670	33,440

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, 2012, our properties were located exclusively in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana. Those properties spanned 12 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. Our properties, the majority of which were acquired in July 2008, cover an estimated 32,027 gross/net acres with 98% of this acreage held by production without near-term lease expirations. Most of our properties offer multiple stacked reservoir objectives with substantial behind pipe potential. We continually seek to enhance our acreage position through leasing and evaluation of opportunistic acquisitions both within the transition zone and beyond.

To that end, during the first quarter of 2013, we bid on, and were the apparent high bidder with respect to, four leases totaling 19,814 acres in the Central Gulf of Mexico and, subject to review of the bids and final award of the leases by the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), will add to our properties holdings in the Gulf of Mexico shelf.

As of December 31, 2012, our total proved reserves were 17.2 MMBoe, consisting of 8.4 MMBbls of oil and 52.9 Bcf of natural gas. The PV-10 of our proved reserves at December 31, 2012 was $407 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $443 million. Additionally, we had probable reserves of 13.3 MMBoe, consisting of 5.9 MMBbls of oil and 45.0 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities.

During 2012, we produced 1,116 MBoe, of which 61% was oil. As of December 31, 2012, our development opportunities included 58 proved behind pipe and shut-in opportunities in 7 fields, 89 proved undeveloped opportunities within 28 proposed wells in 4 fields and 31 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2012, we had 38 probable undeveloped opportunities within 26 proposed wells in 4 fields, 13 possible behind pipe and shut-in development opportunities and 87 possible undeveloped opportunities within 29 proposed wells in 3 fields. During the year ended December 31, 2012, we completed 3 development wells, 2 of which were completed as duals, 12 recompletions in 5 fields and 16 workovers in 5 fields. At year-end, we had one additional developmental well that had finished the drilling and logging and was awaiting completion. The well was successfully completed during the first quarter of 2013.

We operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. As a result of declaring bankruptcy and the absence of availability under our credit facilities, we operated in a liquidity constrained environment from early 2009 through March 2011.

Recent Developments

The following significant events, among others, affected our operations and financial position during 2010, 2011 and 2012:

Operation in, and Exit from, Bankruptcy

As noted above, from March 31, 2009 until May 14, 2010, we operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code. During that period, and continuing into 2011, our operations and financial position were characterized by limited access to capital and limited flexibility in carrying out development plans and increased legal, administrative and other costs associated with operations in bankruptcy, including the incurrence of $0.2 million, $0.4 million and $2.2 million of reorganization costs in 2012, 2011 and 2010, respectively.

On May 14, 2010, our plan of reorganization (the "Plan") became effective, our existing debt facilities were amended and we exited bankruptcy.

Under the Plan (1) our revolving credit facility was amended (the "Amended Revolving Credit Facility") as to maturity date and interest rate and claims under the facility were allowed in the amount of $23.5 million (including outstanding letters of credit), of which $5.5 million was paid on exit from bankruptcy; (2) our term credit facility was amended and restated (the "Amended Term Credit Facility") as to maturity and interest rate and claims under the term credit agreement were allowed in the amount of $127.5 million; (3) mineral royalties with accrued interest and penalties owing the Louisiana Department of Mineral Resources were allowed in the amount of $2.0 million (the "Mineral Royalty Claims") and were payable in 24 monthly installments; (4) amounts owing on notes payable (the "Management Notes") to officers were allowed in the amount of $0.7 million and were payable in full, including compound accrued interest, in 40 months; (5) allowed claims (the "Other Allowed Claims") of substantially all other secured and unsecured creditors, totaling approximately $15.0 million were payable, with interest and legal fees, in full with between 75% and 80% of the allowed claims being paid on exit from bankruptcy and the balance being payable in quarterly installments over one year; (6) warrants (the "Wayzata 2010 Warrants") to purchase 2,000,000 shares of our common stock was issued to the administrative agent for the revolving and term credit facilities; and (7) 483,310 shares of common stock were issued pro rata among the holders of Other Allowed Claims.

During 2011, all remaining unpaid allowed claims under the Plan were paid in full, including the Mineral Royalty Claims, the Management Notes and the Other Allowed Claims and all amounts owing under the Amended Revolving Credit Facility and the Amended Term Credit Facility were repaid in full, and the facilities were terminated, in July 2011 (see "Retirement of Debt and Cancellation of the Wayzata 2010 Warrant" below).

Drilling and Development Activities

From early 2009, and continuing following our May 2010 exit from bankruptcy, through the end of the first quarter 2011, we pursued development activities at a curtailed pace supported by our operating cash flow and cash on hand. With our receipt of equity funding (discussed below) in April and July 2011 and improved profitability we increased our capital budget in 2011 and 2012.

Supplemented by our increased liquidity and capital budget, we accelerated the pace of our development program beginning in April 2011. During 2012 and 2011, we invested $59.8 million and $25.9 million, respectively, in our drilling and development program and infrastructure projects, up from $9.9 million invested in 2010, summarized as follows:

Development Drilling. During 2012 and 2011, we drilled three and two development wells, respectively.

The SL 20436-1 "Catina" well, in Breton Sound 51 Field, was spud in July 2011 and completed in August 2011. The well logged 15 net feet of oil pay in the 10,000' sand. The well began production on August 29, 2011 and was tied back to our Main Pass 46 field facilities.

The MP 47 SL 195QQ-24 "Roux" well, in Main Pass 47 Field, was completed in September 2011. The well reached a total depth of 10,085' MD/9,200' TVD) and encountered 13 pay sands with over 100 net feet of pay. The well was tested and completed in the 21 sand (previously booked as probable reserves). Of the sands encountered, six were previously reflected in our reserves as proved undeveloped, one was reflected as probable undeveloped and six were not previously reflected in our reserves. The well was tied back to our Main Pass 52 facility for high pressure gas sales and to Grand Bay facilities for low pressure gas and liquids.

The SL 195QQ-202 "Jupiter" well, in Grand Bay Field, was spud in July 2012 and completed in August 2012. The well reached total depth of 9,688 feet MD/TVD and encountered 104 feet of net pay in 15 sands between 5,516-9,042 feet and was completed in the 15 sand. The well tested on August 14, 2012 at a gross rate of 245 BOPD and 650 MCFPD, or net 254 BOEPD, on 15/64" choke with FTP of 860 psi.

The SL 20433-1 "North Tiger" well, in Breton Sound 18 Field, was spud in July 2012 and completed in October 2012. The well reached total depth of 9,532 feet MD/9,300 feet TVD and encountered 59 feet of net pay in 6 sands and was completed as a dual producer. The well tested on October 15, 2012 at a gross rate of 517 BOPD and 1,457 MCFPD on a 14/64" choke with FTP of 1,900 psi from the 7,100' sand in the short string and 258 BOPD and 351 MCFPD on a 17/64" choke with FTP of 580 psi from the Cib Carst sand in the long string, or combined net 840 BOEPD.

The SL 3763-14 "Mesa Verde" well, in Vermilion 16 Field, was spud in May 2012 and completed in October 2012. The well reached a total depth of 16,258 feet MD/ TVD and encountered up to 15 potentially productive intervals, including the Marg A, LF, Rob 54 and Amph B sands between 11,333-15,890 feet and was completed in the LF-H sand. The well tested on October 12, 2012 at a gross rate of 190 BOPD, 4,066 MCFPD, or net 685 BOEPD, on a 14/64" choke with flowing tubing pressure ("FTP") of 4,300 psi.

Exploratory Drilling. During 2011, we drilled one exploratory well, the Rio Grande well which was a dry hole.

Recompletion and Workover Program. During 2012, we carried out 12 recompletions and 16 workovers. Eleven of the recompletions and all of the workovers were successful.

During 2011, we carried out 9 recompletions and 25 workovers. Seven of the recompletions were successful, with two recompletions not reaching their objectives due to mechanical issues, although the reserves will stay on the books and be accessed through future development drilling.

Infrastructure Program. During 2012, we invested in \$3.5 million in infrastructure improvements and additions to support existing production and anticipated increases in production.

During 2011, we invested \$5.6 million in infrastructure improvements and additions to support existing production and anticipated increases in production. Principal infrastructure projects during 2011 included installation of a replacement compressor at the Main Pass 25 Field to support higher production from wells supported by that facility through increased compression for gas lift, installation of an 8-mile high pressure pipeline to re-direct production from certain wells and commencing expansion of our Breton Sound 32 facility with increased compression.

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. Our near term development plans are focused on proved undeveloped opportunities and conversion of PDNP opportunities. We presently anticipate drilling 5 to 6 proved undeveloped wells during 2013 and 5 to 6 development wells annually thereafter from an existing inventory of 28 proved undeveloped wells. We have also targeted between 15 to 20 recompletions and/or workovers to be undertaken during 2013. We have already drilled and completed the MP 47 SL 195QQ-25 "Roux Toux" well in the Main Pass 47 field during the first quarter of 2013 and this well has been tied back to the Company's Grand Bay facilities.

In addition to our program of proved undeveloped, PDNP, recompletion and workover opportunities, during 2012 we continued efforts to protect, and secure partners for the exploration and development of, ultra-deep prospects in our Grand Bay and Vermilion 16 fields and, in early 2013, bid on, and were the apparent high bidder with respect to, four leases totaling 19,814 acres in the shallow Gulf of Mexico shelf. Those efforts included drilling of our Mesa Verde well in Vermilion 16, located in the heart of a trend presently the subject of a number of exploratory ultra-deep wells presently being undertaken by larger operators. The Mesa Verde well, while not an ultra-deep well, identified a number of potentially productive sands and is expected to enhance the preservation of our lease position in the field. We continue to monitor ongoing ultra-deep exploratory projects and to conduct high level discussions with potential partners in an ultra-deep drilling program should the existing exploratory projects prove successful. We also intend to seek partners to develop and operate the shallow Gulf of Mexico shelf prospects via farm-outs, promoted deals or other similar arrangements. As of March 2013, we had not yet entered into a joint venture, or other, agreement with respect to exploratory drilling of our ultra-deep prospects or development of our shallow Gulf of Mexico shelf 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.

Effects of Hurricane Isaac

Hurricane Isaac resulted in a disruption of production and the shut-in of 100% of our wells for a period of 17 days beginning August 26 and ending September 11, 2012 and reduced production while wells were brought back on line over the balance of 2012. The delay in returning field to productive status was primarily attributable to delays in third party pipeline transportation. We experienced minimal damage to our asset base and estimate total gross repair cost at \$2.8 million, of which \$2.4 million is expected to be covered by insurance. As of December 31, 2012, substantially all repairs arising from Hurricane Isaac had been completed and all of the wells had been returned to productive status. The hurricane also caused delays in the installation of the flowlines and facility infrastructure required for the North Tiger (SL 20433 #1/1D) well, which delayed our initial production startup by approximately 30 days, and pushed back a number of wells in our development schedule.

Leasehold and Seismic Activity

Termination of Clayton Williams Energy Farmout in Grand Bay Field. During 2011, we terminated our farmout agreement with Clayton Williams Energy covering approximately 2,000 gross acres in the northwest portion of our Grand Bay Field. Pursuant to the termination of that farmout, we paid to Clayton Williams Energy $506,425 and assumed full control, operation and ownership of 100% of the working interest in the subject acreage.

Seismic Activities. During 2010, we purchased a license for 3D seismic covering 42.88 blocks (330 square miles) in Breton Sound. Pursuant to the license agreement we paid an initial installment in May 2010 of $185,000 and, beginning June 1, 2010, made monthly installments of $80,000 for ten months ending March 2011.

Gulf of Mexico Shelf Acreage. In March 2013, we bid on, and were the apparent high bidder relative to, 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. Final award of the leases is subject to BOEMRE review. Lease bonuses on the prospects total $880,000 and first year annual rentals total $138,698. Additionally, assuming final award of the leases, we will pay a prospect fee of $450,000 to a third party consultant.

Hedges

In February 2010, the administrative agent under our credit facilities liquidated all of our existing hedge contracts and applied the proceeds thereof to amounts owed under the facilities. As a result, our production was unhedged from February 2010 through the third quarter of 2012.

During the quarter ended September 30, 2012, we resumed our hedging program under which, 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, 2012, we had in place fixed price swaps covering an aggregate of 1,000 to 1,500 barrels of oil per day, or an aggregate of 245,300 barrels of oil over the period beginning October 2012 and ending March 2013, at prices ranging from $106.00 to $108.50 per barrel. Subsequent to December 31, 2012, we entered into an additional swap contracts covering 500 to 1,000 barrels of oil per day, or an aggregate of 297,000 barrels of oil over the period beginning April 2013 and ending March 2014, at prices ranging from $106.82 to $109.20 per barrel.

Compensation

In March 2011, our board of directors approved a revised compensation program for non-employee directors, consisting of annual stock option grants to acquire 35,000 shares of stock, together with cash retainers for board service and committee chairs. The options are exercisable for terms of seven years and vest 50% on the grant date and 50% on the first anniversary of the grant date.

In July 2011, we paid one-time bonuses totaling $225,000 to five officers and key employees principally involved in our financing efforts described below.

In March 2012, our compensation committee approved bonuses totaling $200,000 to two officers relating to services during 2011. Those bonuses were recorded as compensation expense and are reflected in general and administrative expenses during 2011.

In March 2012, our board of directors approved the adoption of the 2012 Annual Incentive Program which is intended to establish potential bonus payouts tied to satisfaction of performance criteria and established broad company performance criteria. Full payout under the program would result in bonuses of approximately $1.9 million. $190,553 of compensation expense was reported during 2012 based on accrual of estimated bonus payments under the program.

Stock Option Activity

During 2010, our board of directors approved stock option grants, effective on exit from bankruptcy, to purchase an aggregate of 845,000 shares of common stock to our directors and to various key employees, including an aggregate of 50,000 stock options granted to directors and 150,000 stock options granted to an officer. The options are exercisable at $3.00 per share for a term of ten years. The options were subject to different vesting periods.

In addition, during 2010, we granted stock options to purchase an aggregate of 447,500 shares of common stock to newly hired and existing employees and consultants, including 140,000 stock options granted to two officers, with exercise prices ranging from $1.39 to $1.71 per share. The options were subject to different vesting periods, including performance based vesting with respect to options granted to a consultant.

As a result of the stock option grants during 2010, we recorded $471,946 of compensation charges that are reflected in general and administrative expense.

During 2010, a total of 350,000 stock options were forfeited.

During 2011, we granted stock options to purchase an aggregate of 105,000 shares of common stock to non-employee directors, including one newly appointed director. The options had exercise prices ranging from $2.80 to $3.05 per share and vested 50% on the grant date and 50% one year from the grant date

In addition, during 2011, we granted stock options to purchase an aggregate of 290,000 shares of common stock to newly hired employees, including one newly hired executive, with exercise prices ranging from $2.75 to $5.63 per share.

As a result of the stock option grants during 2011, we recorded $471,173 of compensation charges that are reflected in general and administrative expense.

During 2011, a total of 201,667 stock options were forfeited.

During 2012, we granted stock options to purchase an aggregate of 105,000 shares of common stock to non-employee directors. The options are exercisable at $6.65 per share, had a term of seven years and vest 50% on the grant date and 50% one year from the grant date.

In addition, during 2012, we granted stock options purchase an aggregate of 5,000 shares of common stock to a non-executive employee. The options are exercisable at $6.40 per share, had a term of seven years and vest 50% on the grant date and 50% one year from the grant date.

As a result of the stock option grants during 2012, we recorded $1,205,919 of compensation charges that are reflected in general and administrative expense.

During 2012, a total of 75,000 stock options were forfeited.

As of December 31, 2012, total compensation cost related to unvested stock option awards not yet recognized in earnings was approximately $0.5 million, which is expected to be recognized over a weighted average period of approximately 0.59 years.

Consulting Agreements and Fees

During 2010, we retained the services of a non-affiliate consulting geophysicist to assist in advanced geophysics applications relating to our exploration development program and retained the services of a non-affiliate finance and business development consultant to assist in strategic, industry partnering and financial market planning in order to accelerate our development activities. Pursuant to those consulting arrangements, we granted certain stock options and paid monthly cash consulting fees.

During 2011, we terminated the consulting agreement for finance and business development services.

Share and Warrant Issuances

Share Issuances. In April 2011, we sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 2,481,316 shares of common stock and warrants to purchase 1,240,658 shares of common stock. The shares and warrants were offered in units of two shares and one warrant at $6.00 per unit for aggregate gross proceeds of $7.4 million. The warrants are exercisable for two years to purchase shares of common stock at $5.00 per share. Pursuant to the offering, we issued 84,600 shares of common stock and warrants to purchase 42,300 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

In July 2011, we sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 5,650,000 shares of common stock at a price of $5.00 per share. Net proceeds from the sale of shares were approximately $27.3 million of which $20.0 million was deposited directly into a third party escrow account to be applied to retirement of indebtedness under our prior credit facilities. Pursuant to the offering, we issued 38,200 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

During 2011, we sold 45,000 shares of common stock for $43,200 in cash pursuant to the exercise of outstanding stock options.

During 2011, we issued an aggregate of 1,055,516 shares of common stock pursuant to the exercise of warrants. A warrant to acquire 805,516 shares of common stock at $0.01 per share was exercised on a "cashless" basis pursuant to which the intrinsic value of the warrant was delivered in lieu of a cash payment of the exercise price, resulting in the issuance of 803,764 shares and a warrant to acquire 250,000 shares of common stock at $0.25 per share was exercised on a "cashless" basis pursuant to which the intrinsic value of the warrant was delivered in lieu of a cash payment of the exercise price, resulting in the issuance of 239,984 shares.

During 2012, we sold, in a private placement, an aggregate of 3,089,360 shares of common stock to certain institutional and accredited investors at a price of $6.25 per share, for net proceeds of approximately $18.4 million.

During 2012, we sold 163,500 shares of common stock for $402,256 pursuant to the exercise of outstanding stock options and sold 892,327 shares of common stock for $4.5 million pursuant to the exercise of outstanding stock warrants.

Warrant Issuances. During 2010, we sold to a service provider, for a purchase price of $100, a warrant to purchase 40,000 shares of common stock. The warrant is exercisable at $3.00 per share for a term of five years.

During 2012, in connection with the early exercise of outstanding warrants, we issued warrants to purchase an aggregate of 106,997 shares of our common stock for a term of three years at $8.00 per share.

Sale of 2016 Notes

In July 2011, we and our subsidiaries (the "Guarantors") entered into a Purchase Agreement with Imperial Capital, LLC, relating to the issuance and sale of $127.5 million in aggregate principal amount of our 12.5% Senior Secured Notes due 2016 (the "2016 Notes"). The 2016 Notes were sold at 98.221% of par. The 2016 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act of 1933 (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, we and the Guarantors entered into a Purchase Agreement with Imperial Capital, LLC relating the issuance and sale of an additional $25.0 million in aggregate principal amount of additional 2016 Notes. The 2016 Notes were sold at 98.58% of par plus accrued interest from July 1, 2012. The additional 2016 Notes were offered and sold 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 and to persons outside of the U.S. pursuant to Regulation S.

The 2016 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.

The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

The indenture, as supplemented in connection with the 2012 offering (the "Indenture"), pursuant to which the 2016 Notes were issued 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.

We have the option to redeem all or a portion of the 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest. We may also redeem the 2016 Notes, in whole or in part, at a "make-whole" redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, we may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, we may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

At December 31, 2012, the aggregate principal amount of 2016 Notes outstanding was $152.5 million.

Registration Rights Agreements

In connection with the 2011 and 2012 issuance and sale of the 2016 Notes, we and the Guarantors entered into separate registration rights agreements (the "Registration Rights Agreements") with Imperial Capital. Pursuant to the Registration Rights Agreements, we and the Guarantors agreed to file registration statement with the Securities and Exchange Commission (the "SEC") so that holders of the 2016 Notes could exchange the 2016 Notes for registered notes that have substantially identical terms as the 2016 Notes. In addition, we and the Guarantors agreed to exchange the guarantee related to the 2016 Notes for a registered guarantee having substantially the same terms as the original guarantee. We and the Guarantors agreed to use reasonable best efforts to cause a registration statement with respect to the exchange to be filed within 90 days after the issuance of the 2016 Notes and declared effective under the Securities Act within 180 days after the issuance of the 2016 Notes. In the event of a failure to comply with our obligations to register the 2016 Notes within the specified time periods or to continue to maintain the effectiveness of the registration (a "Registration Default"), the interest rate on the 2016 Notes will be increased by 0.25% for each 90 days that such Registration Default continues, provided that the increase in interest rate shall in no event exceed an aggregate of 1.0% and provided, further, that upon cure of any such Registration Default the interest rate on the 2016 Notes will be reduced to its original rate. A registration statement relating to the exchange of the 2016 Notes issued during 2011 was filed on September 26, 2011 and was declared effective by the SEC on October 19, 2011. Following the effectiveness of the registration statement, we completed the exchange of registered notes for the unregistered 2016 Notes issued in 2011. A registration statement relating to the exchange of the 2016 Notes issued during 2012 was filed on January 11, 2013 and was declared effective by the SEC on February 6, 2013. Following the effectiveness of the registration statement, we completed the exchange of registered notes for the unregistered 2016 Notes in 2012.

In connection with the July 2011 issuance and sale of shares, we entered into a registration rights agreement (the "2011 Equity Registration Rights Agreement") with the purchasers of the shares. Pursuant to the 2011 Equity Registration Rights Agreement, the holders of a majority of the shares will have a demand registration right pursuant to which we may be required to file with the SEC one or more registration statements covering the resale of the shares. Additionally, the 2011 Equity Registration Rights Agreement provides "piggyback" registration rights to the holders of the shares pursuant to which the holders are entitled to notice of the filing of certain registration statements and inclusion of some or all of the shares in any such registration statements.

In connection with the 2012 issuance and sale of shares, we entered into a registration rights agreement (the "2012 Equity Registration Rights Agreement") with the purchasers of the shares. Pursuant to the 2012 Equity Registration Rights Agreement, we undertook to file a registration statement covering the shares not later than thirty days after the closing date of the offering. In the event that we failed to file the required registration statement within said thirty day period, failed to cause the registration statement to become effective within ninety days (120 days if the registration statement was subject to review by the SEC), failed to cause the shares to be listed for quotation on an approved market or otherwise fails to either maintain the continuing effectiveness of the registration statement or to make such filings with the SEC so as to permit resales under Rule 144, we agreed to pay as partial liquidated damages one percent of the aggregate purchase price of the shares for each thirty days in which such condition continues.

On June 20, 2012, we filed a registration statement covering the resale of, among other shares, the shares covered by the 2011 Equity Registration Rights Agreement and the 2012 Equity Registration Rights Agreement. That registration statement was declared effective by the SEC on July 5, 2012.

Retirement of Debt and Cancellation of Wayzata 2010 Warrants

In July 2011, we repaid in full all outstanding indebtedness under our prior credit facilities with a portion of the proceeds from the July 2011 sale of 2016 Notes and shares and, in conjunction therewith, retired letter of credit obligations totaling $10.2 million. Further, the warrants issued to Wayzata (the "Wayzata 2010 Warrants") to purchase 2,000,000 shares issued to the administrative agent of those facilities, dated May 14, 2010, were cancelled in connection with the repayment of the indebtedness. As a result of retirement of the debt and cancellation of the Wayzata 2010 Warrants, the Company realized a gain on extinguishment of debt of $7.7 million, wrote off $2.8 million of unamortized debt discount and debt issuance costs and reduced additional paid-in capital by $10.6 million.

Retirement of Uncontested Bankruptcy Claims

During 2011, we paid the balance owing with respect to the state lessor royalty audit (excluding penalties with respect to which we received a waiver) and notes payable to officers, being the last of the unpaid uncontested claims under our Plan of Reorganization. Amounts paid in settlement of uncontested claims under our Plan of Reorganization totaled $3.2 million during 2011.

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 prepare the estimates of our oil and gas reserves presented in this report 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 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 2012 year-end reserve report, we used an average oil price of $106.51 per Bbl, and a natural gas price of $5.13 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, 2012 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 to 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.

Debt Modification

Pursuant to the provisions of our Plan of Reorganization and under the terms of an Amended and Restated Term Credit Agreement, our term credit facility was revised during 2010 to reflect the total amount borrowed and owing thereunder of $127.5 million and to provide for accrual of interest at 11.25% per annum payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012. The principal amount owing under the term note included interest expense and certain reorganization costs totaling $30.0 million that were capitalized as part of the aggregate principal amount payable on the term loan.

In evaluating the accounting for the debt restructuring under the Plan of Reorganization, we were required to make a determination as to whether the debt restructuring should be accounted for as a Troubled Debt Restructuring ("TDR") or as an extinguishment or modification of debt. The relevant accounting guidance required us to determine first whether the exchanges of debt instruments should be accounted for as a TDR. A TDR results when it is determined that a debtor is experiencing financial difficulties and the creditors grant a concession; otherwise, such exchanges should be accounted for as an extinguishment or modification of debt. The assessment of this critical accounting estimate required management to apply a significant amount of judgment in evaluating the inputs, estimates, and internally generated forecast information to conclude on the accounting for the debt restructuring.

We then evaluated if the debt restructuring constituted a material modification, in which case the debt restructuring would be accounted for as an extinguishment of the original debt and the creation of new debt, resulting in the recognition of a gain or loss on the extinguishment of debt. If it was determined that the debt restructuring was a TDR, then there is no recognition of gain or loss on the extinguishment of debt, and the carrying amount of the debt is adjusted for any premium or discount that is amortized over the modification period.

Based on analysis performed and after the consideration of the applicable accounting guidance, management concluded that the debt restructuring was deemed to be a TDR. The debt restructuring was determined to be a TDR based on the creditors being deemed to have granted a concession since our effective borrowing rate of 13.93% on the restructured debt is less than the 22.15% effective borrowing rate of the old debt immediately prior to the restructuring. Accordingly, the effects of the restructuring were accounted for prospectively from the time of the restructuring, and the restructured debt has been recorded with premiums which reflect the carrying value of the old debt less the fair value of 2,000,000 warrants for common stock issued to the creditors.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Oil and Gas Revenue

Oil and gas revenue for the year ended 2012 increased by 8% to $82.5 million from $76.2 million in 2011.

The increase in revenue was attributable to an 18% increase in production volumes partially offset by an 8% decline in average hydrocarbon prices realized during 2012. 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, 2012 and 2011:

	2012	2011
Revenues		
Oil	$ 72,959,377	$ 65,649,756
Gas	9,569,555	10,509,512
Total oil and gas revenues	$ 82,528,932	$ 76,159,268
Production		
Oil (Bbls)	676,400	605,900
Gas (Mcf)	2,639,500	2,038,000
Total production (Boe)	1,116,317	945,567
Average sales price		
Oil (per Bbl)	$ 107.86	$ 108.35
Gas (per Mcf)	3.63	5.16
Total average sales price (per Boe)	$ 73.93	$ 80.54

The increase in production volumes during 2012 was attributable to increased investment in, and acceleration of, our drilling, recompletion and workover program and investments in infrastructure projects to eliminate bottlenecking and infrastructure related constraints on production. Beginning in the second quarter of 2011 and continuing through 2012, we have substantially increased our investment in our drilling and development program, with investments totaling $56.3 million in 2012 as compared to $20.3 million in 2011 up from $7.7 million in 2010. The gains in production volumes attributable to increased investment in our drilling and development program, and infrastructure projects, was partially offset during 2012 by the shut-in of production attributable to Hurricane Isaac and the following transition period to ramp production up to pre-hurricane levels.

The decrease in average prices realized from the sale of oil and gas reflected continued weakening of natural gas prices during much of 2012 combined with slightly weaker prices realized from crude oil sales. Our crude oil prices realized reflect a premium to prevailing WTI prices as a result of the quality of our LLS and HLS oil production. Prior to our reinstitution of a hedging program during the third quarter of 2012, we were fully unhedged and benefited from favorable crude oil pricing while also being exposed to declining natural gas prices. With the institution of our hedging program late in the third quarter, approximately 22% of our crude oil production volume during 2012 was sold under hedging arrangements. None of our natural gas production was sold under hedging arrangements during 2012

Other Revenues

Other revenues consist principally of (i) a net profits interest attributable to operating the Breton Sound 31 field, for which we receive a percentage of profits, (ii) production handling fees from our Vermilion 16 field, (iii) during 2012, settlements of lawsuits against the former owners of The Harvest Group LLC and Harvest Oil & Gas, LLC and (iv) during 2011, refunds of severance taxes under a Louisiana incentive program relating to previously inactive wells. For 2012, other revenues decreased to $1.4 million from $4.8 million in 2011. The decrease in other revenue was principally attributable to the one-time nature of the severance tax refunds totaling $2.6 million during 2011.

Operating Expenses

Operating expenses increased by 28.8% to $71.7 million for 2012 from $55.7 million in 2011. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2012 and 2011:

	2012		2011	
	Total	Per Boe	Total	Per Boe
Lease operating expense	$ 19,317,283	$ 17.30	$ 17,123,890	$ 18.11
Workover expense	3,828,197	3.43	2,666,600	2.82
Exploration expense	547,192	0.49	596,065	0.63
Loss on plugging and abandonment	2,468,969	2.21	393,599	0.42
Dry hole costs	93,353	0.08	3,912,823	4.14
Depreciation, depletion and amortization	27,407,700	24.55	15,591,048	16.49
Impairment expense	401,752	0.36	641,791	0.68
Accretion expense	1,510,165	1.35	1,672,900	1.77
Gain on revision of asset retirement obligations	(245,007)	(0.22)	(303,633)	(0.32)
Gain on purchase price adjustment	-	-	(1,426,778)	(1.51)
General and administrative expenses	8,584,486	7.69	8,704,536	9.21
Severance taxes	7,768,426	6.96	6,090,666	6.44
	$ 71,682,516	$ 64.21	$ 55,663,507	$ 58.88

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

Lease Operating Expense

Lease operating expenses for 2012 increased 12.8% to $19.3 million from $17.1 million in 2011, but on a per BOE basis decreased 4.4% to $17.31 per BOE from $18.11 per BOE in 2011.

Operating costs in our fields have historically been relatively high due to water handling, the need for gas lift to maintain oil production and due to the need for marine transportation in the shallow water, bay environment. The increases in operating expenses during 2012 were primarily attributable to an increase in production volumes and an increase in operating expenses on third party operated properties and increases in transportation expenses. The increase in lease operating expense on a per BOE basis was primarily attributable to the fixed nature of certain lease operating expenses combined with the losses of production attributable to Hurricane Isaac.

Workover Expense

Workover expense for 2012 increased 43.6% to $3.8 million from $2.7 million in 2011. The increase in workover expense was attributable to an increase in the number of workovers completed in 2012.

Exploration Expense

Exploration expense for 2012 decreased 8.2% to $0.5 million from $0.6 million in 2011. Exploration expenses during 2012 and 2011 principally relate to delay rental payments.

Loss on plugging and abandonment

Loss on plugging and abandonment increased to $2.5 million in 2012 from $0.4 million in 2011. The loss in each year reflects plugging and abandonment costs in excess of estimated costs reflected in our asset retirement obligation liabilities. The increase in loss reflected our determination to plug orphaned wells on expired leases in Little Bay, South Atchafalaya Bay and Crooked Bay which we inherited from the previous owners and have never produced since we have owned the assets. Four of the wells plugged were the deepest and highest pressure wells in our inventory of wells to be plugged. In addition several of the wells had unanticipated severe casing damage. Accordingly, the actual costs incurred in plugging and abandoning these wells was substantially higher than we estimated and would expect to incur in future plugging operations.

Dry Hole Costs

Dry hole costs decreased to $0.1 million in 2012 from $3.9 million in 2011. The decrease in dry hole costs reflects the cost of the Rio Grande well which was drilled as a dry hole during 2011.

Depreciation, Depletion and Amortization (DD&A)

Depreciation, depletion and amortization for 2012 increased 75.8% to $27.4 million from $15.6 million in 2011. The increase in DD&A was attributable to increased production, added capital expenditures and a reduction in natural gas reserves associated with certain properties, most notably the Mesa Verde well, where sands were thinner than anticipated, and Little Bay, where increased capital costs in our reserve report resulted in a reduction in reserves. 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 2012 decreased 37.4% to $0.4 million from $0.6 million in 2011. Impairment expense during 2012 related to our Breton Sound 51 Field and was a result of one of the three producing wells in the field becoming fully depleted during the year. Impairment expense during 2011 related to one property on which development costs and carrying value, combined, were determined to exceed fair value.

Accretion expense

Accretion expense for 2012 decreased 9.7% to $1.5 million from $1.7 million in 2011. 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 was $0.2 million in 2012 as compared to $0.3 million in 2011. These gains are due primarily to downward revisions in the asset retirement obligations relating to two properties which exceeded the carrying amount of the property

Gain on purchase price adjustment

Gain on purchase price adjustment was $0 in 2012 and $1.4 million in 2011. Gain on purchase price adjustment arose from adjustments to the original purchase price of certain of our assets, relating to site specific trust accounts, which occurred longer than one year after the acquisition date.

General and Administrative Expense

General and administrative expense for 2012 decreased 1% to $8.6 million from $8.7 million in 2011, and decreased 16.5% on a per BOE basis. The decrease in general and administrative expense was primarily attributable to reduced personnel costs and reduced legal expenses

Severance Taxes

Severance taxes for 2012 increased 27.5% to $7.8 million from $6.1 million in 2011 and increased 8.1% from $6.44 per BOE in 2011 to $6.96 per BOE in 2012. The increase was primarily due to increased production and by a decrease in the number of inactive wells eligible for certain Louisiana severance tax exemptions.

Other Income (Expense), Net

Net other expenses totaled $17.6 million for 2012 as compared $10.8 million for 2011. The following table sets forth the components of net other income (expenses) for 2012 and 2011:

	2012	**2011**
Financing expense	(7,527)	(837,364)
Gain on extinguishment of debt	—	7,708,486
Interest expense (net)	(17,619,063)	(17,698,849)
	$ (17,626,590)	$ (10,827,727)

Financing Expense. Financing expense totaled $0.8 million during 2011 and consisted of commitment fees and costs associated with the planned establishment of a revolving credit facility during 2011. We opted to seek more favorable credit terms in lieu of closing the revolving credit facility resulting in our expensing all costs associated with efforts to establish the facility.

Gain on Extinguishment of Debt. Gain on extinguishment of debt totaled $7.7 million during 2011. The gain on extinguishment of debt relates to the 2011 retirement of indebtedness under our prior credit facilities and reflects the fair market value of the warrants cancelled on retirement of that debt net of unamortized debt issuance costs and debt discount.

Interest Expense, Net. Interest expense, net, for 2012 remained virtually unchanged at $17.6 million as compared to $17.7 million in 2011. Interest expense, net reflects interest incurred on debt under our senior secured notes and our prior term credit agreement and revolving credit agreement, partially offset by interest earned on cash balances held. The decrease in net interest expense was attributable to a reduction in our average outstanding indebtedness. With our placement of an additional $25.0 million in principal amount of senior secured notes in December 2012, our interest expense is expected to increase during 2013.

Reorganization Expenses

Reorganization expenses reflect payments to professionals and other fees incurred in connection with our prior Chapter 11 case. Reorganization expenses decreased to $0.2 million in 2012 from $0.4 million in 2011 due to our exit from bankruptcy in May 2010.

Income Tax Provision (Benefit)

For 2012, we recorded income tax benefit of $1.8 million compared to $6.8 million during 2011. The income tax benefit during 2012 and 2011 primarily reflects recognition of a deferred tax asset relating to our net operating loss carryforwards.

Our effective tax rates for 2012 and 2011 were 32.1% and (49.1)%, 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.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

As noted previously in this report, we operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. During that period, and continuing through completion of our capital raising efforts in mid-2011, our operations, and operating results, were significantly affected by, among other things, our incurrence of substantial expenses directly and indirectly related to our bankruptcy and the curtailment or delay of investments in our development program and normal field maintenance operations arising from the cumbersome and slow process of obtaining various approvals required for use of cash and our inability to draw on our revolving credit facility.

Oil and Gas Revenue

Oil and gas revenue for the year ended 2011 increased by 44.6% to $76.2 million from $52.7 million in 2010.

The increase in revenue was attributable to a 31.9% increase in average hydrocarbon prices realized during 2011 and a 9.5% increase in production volumes. 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, 2011 and 2010:

	2011	2010
Revenues		
Oil	$ 65,649,756	$ 44,141,235
Gas	10,509,512	8,592,972
Total oil and gas revenues	$ 76,159,268	$ 52,734,207
Production		
Oil (Bbls)	605,900	550,000
Gas (Mcf)	2,038,000	1,882,800
Total production (Boe)	945,567	863,800
Average sales price		
Oil (per Bbl)	$ 108.35	$ 80.26
Gas (per Mcf)	5.16	4.56
Total average sales price (per Boe)	$ 80.54	$ 61.05

The increase in production during 2011 was attributable to our recompletion and workover program, drilling of our Catina and Roux wells and efforts during 2011 to address deferred maintenance and third party facilities capacity limitations that resulted in the resumption of production or increase in production from shut-in wells and wells producing below capacity. The increase in production during 2011 reflects additional investment in, and acceleration of, our development and drilling plan commencing in the second quarter of 2011 which, in turn, reflected our strengthened cash position attributable to capital raising efforts and improved operating cash flows. Investments in our drilling and development program totaled $20.3 million in 2011 as compared to $7.7 million in 2010.

The increase in average prices realized from the sale of oil and gas reflected a sharp rise in global commodity prices, in particular crude oil prices, beginning in late 2010 and continuing through 2011. Our increase in average prices realized also reflects a premium to prevailing WTI prices as a result of the quality of our LLS and HLS oil production. At December 31, 2011, we were fully unhedged and, during 2011, benefited from rising oil prices and premiums to prevailing WTI prices while also being exposed to declining natural gas prices.

Other Revenues

Other revenues consist principally of (i) a net profits interest attributable to operating the Breton Sound 31 field, for which we receive a percentage of profits, (ii) production handling fees from our Vermilion 16 field, (iii) in 2010, proceeds from the sale of our Adcock Farms lease and well, and (iv) in 2011, refunds of severance taxes under a Louisiana incentive program relating to previously inactive wells. For 2011, other revenues increased to $6.2 million from $2.3 million in 2010. The increase in other revenues was principally attributable to severance tax refunds of $2.6 million received during 2011.

Operating Expenses

Operating expenses increased by 10.9% to $55.7 million for 2011 from $50.2 million in 2010. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2011 and 2010:

	2011		2010	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 17,123,890	$ 18.11	$ 13,774,406	$ 15.95
Workover expense	2,666,600	2.82	2,154,482	2.49
Exploration expense	596,065	0.63	1,921,943	2.22
Loss on plugging and abandonment	393,599	0.42	-	-
Dry hole costs	3,912,823	4.14	-	-
Depreciation, depletion and amortization	15,591,048	16.49	16,001,826	18.52
Impairment expense	641,791	0.68	-	-
Accretion expense	1,672,900	1.77	1,668,268	1.93
Gain on revision of asset retirement obligations	(303,633)	(0.32)	-	-
Gain on purchase price adjustment	(1,426,778)	(1.51)	-	-
Loss on settlement of accounts payable	-	-	990,786	1.15
General and administrative expenses	8,704,536	9.21	8,476,124	9.81
Severance taxes	6,090,666	6.44	5,214,677	6.04
	$ 55,663,507	$ 58.88	$ 50,202,512	$ 58.11

As more fully described below, the change in operating expenses was primarily attributable to increased lease operating expense, workover expense, loss on plugging and abandonment, dry hole costs and production and severance taxes, partially offset by decreased exploration expense.

Lease Operating Expenses

Lease operating expenses for 2011 increased 24.3% to $17.1 million, or $18.11 per Boe, from $13.8 million, or $15.95 per Boe, in 2010.

Operating costs in our fields have historically been relatively high due to water handling, the need for gas lift to maintain oil production and due to the need for marine transportation in the shallow water, bay environment. We have been actively engaged in field management efforts to reduce our lease operating expenses. The increase in lease operating expenses during 2011 was primarily attributable to increases in equipment rental, transportation expense and field personnel.

Workover Expense

Workover expense for 2011 increased 23.8% to $2.7 million from $2.2 million in 2010. The increase in workover expense was attributable to more workover activity in 2011.

Exploration Expense

Exploration expense for 2011 decreased 69.0% to $0.6 million from $1.9 million in 2010. The decrease in exploration expense was attributable to the completion of our full field study program in early 2011 and the 2010 purchase of a seismic data license ($0.7 million).

Loss on plugging and abandonment

Loss on plugging and abandonment was $0.4 million in 2011 due to the cost of plugging and abandoning wells in the Breton Sound 51 field that exceeded those estimated in our calculation of asset retirement obligation liabilities

Depreciation, Depletion, Amortization and Impairment (DD&A)

Depreciation, depletion and amortization for 2011 decreased 2.6% to $15.6 million from $16.0 million in 2010. Changes in DD&A were attributable to different production rates and added 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. During the year ended December 31, 2011, Saratoga recorded an impairment expense of $0.6 million relating to one property when development costs incurred during the year combined with the existing carrying value exceeded the fair value.

Accretion expense

Accretion expense for 2011 remained unchanged from 2010 at $1.7 million.

Gain on revision of asset retirement obligation

Gain on revision of asset retirement obligation was $0.3 million due to downward revisions in the asset retirement obligations relating to one property which exceeded the carrying amount of the property

Gain on purchase price adjustment

Gain on purchase price adjustment was $1.4 million due to adjustments to the original purchase price of certain of Saratoga's assets, relating to site specific trust accounts, which occurred longer than one year after the acquisition date.

Loss on settlement of accounts payable

Loss on settlement of accounts payable reflects the fair value of the common stock issued, on a one-time basis, to our vendors during 2010 as part of the settlement terms in our plan of reorganization.

General and Administrative Expenses and Other

General and administrative expense for 2011 increased 2.7% to $8.7 million from $8.5 million in 2010. The increase in general and administrative expense was attributable to increased compensation expense ($2.6 million) relating to salary increases, additional head count and cash bonuses partially offset by a decrease in stock-based compensation. The change in stock-based compensation was attributable to broad based stock option grants with immediate vesting during 2010 in connection with our exit from bankruptcy. Non-cash G&A expense, associated principally with stock-based compensation, totaled $0.9 million and $2.6 million in 2011 and 2010, respectively.

Severance Taxes

Severance taxes for 2011 increased 16.8% to $6.1 million from $5.2 million in 2010. The increase was primarily due to increased production and prices partially offset by decreased severance tax rates for our natural gas production that began in July 2010 and severance tax incentives relating to previously inactive wells.

Other Income (Expense), Net

Net other expenses totaled $10.8 million for 2011 as compared $21.8 million for 2010. The following table sets forth the components of net other income (expenses) for 2011 and 2010:

	2011	2010
Commodity derivative income (expense)	$ —	$ 696,550
Financing expense	(837,364)	—
Gain on extinguishment of debt	7,708,486	—
Interest expense (net)	(17,698,849)	(22,469,584)
	$ (10,827,727)	$ (21,773,034)

As more fully described below, the changes in other income (expense), net, were principally attributable to the gain realized in the 2011 on the extinguishment of debt, liquidation of our commodity derivates during 2010, resulting in a gain for 2010 compared to no income or expense from commodity derivatives during 2011, financing expenses incurred during 2011 relating to a revolving credit facility and a decrease in interest expense reflecting a lower average interest rate on borrowed funds.

Commodity Derivative Income (Expense). Commodity derivative income decreased to $0 during 2011 from $0.7 million during 2010. The commodity derivative income recognized during 2010 related to the liquidation of our commodity derivatives during 2010. We had no commodity derivative activities during 2011.

Financing Expense. Financing expense consists of commitment fees and costs associated with the planned establishment of a revolving credit facility during 2011. We opted to seek more favorable credit terms in lieu of closing the revolving credit facility resulting in our expensing all costs associated with efforts to establish the facility.

Gain on Extinguishment of Debt. Gain on extinguishment of debt totaled $7.7 million during 2011. The gain on extinguishment of debt relates to the 2011 retirement of indebtedness under our prior credit facilities and reflects the fair market value of the warrants cancelled on retirement of that debt net of unamortized debt issuance costs and debt discount.

Interest Expense, Net. Interest expense, net, reflects interest incurred on debt under our term credit agreement and revolving credit agreement which were retired in July 2011 and our new senior secured notes which were issued in July 2011, partially offset by interest earned on cash balances held. Net interest expense decreased to $17.7 million in 2011 from $22.5 million in 2010. The decrease in net interest expense was attributable to a May 2010 decrease in our stated interest rate on our Amended and Restated Term Credit Agreement from 20% to 11.25% and, to a lesser extent, an increase in interest income resulting from an increase in our cash balances partially offset by an increase in the stated interest rate of our senior secured notes to 12.5% commencing in July 2011.

Reorganization Expenses

Reorganization expenses reflect payments to professionals and other fees incurred in connection with our Chapter 11 case. Reorganization expenses decreased to $0.4 million in 2011 from $2.2 million in 2010 due to our exit from bankruptcy in May 2010.

Income Tax Provision

For 2011, we recorded an income tax benefit of \$6.8 million compared to income tax expense of \$0.3 million for 2010. The income tax expense for 2010 was attributable to Louisiana state franchise taxes. For 2011, we recognized a deferred tax asset relating to our net operating loss carryforwards.

Our effective tax rates for 2011 and 2010 were (49.1)% and (1.5)%, 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.

Following our exit from bankruptcy in May 2010, we have continued to fund operations out of operating cash flow and cash on hand, which funds have been supplemented by our receipt of funds from our April and July 2011 and May 2012 equity capital raises and our December 2012 issuance of senior secured notes described herein. From prior to our bankruptcy filing in March 2009 through the retirement of our revolving credit facility in July 2011, we did not have access to available capital under our revolving credit agreement. At December 31, 2012, and continuing as of this writing, we had not yet established a revolving credit facility and continue to evaluate multiple potential options regarding the establishment of such a facility.

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 2011, we achieved our principal short-term objectives through substantial investments in infrastructure upgrades. During 2012, while continuing to advance short-term objectives associated with continual investment in our infrastructure, we focused on our mid-term objectives as reflected in an increase in our developmental drilling program.

As noted, we have supplemented our cash and liquidity position through a series of equity capital raises during 2011 and 2012, consisting of (1) the receipt of \$7.4 million from the sale of common stock and warrants in April 2011, (2) the receipt of \$27.3 million from the sale of common stock in July 2011, and (3) the receipt of \$18.4 million from the sale of common stock in May 2012. We have utilized the proceeds from the offerings of such stock and warrants to support accelerated investments in our development and maintenance program.

Further, during July 2011, we received \$120.9 million of net proceeds from the sale of our 2016 Notes and, during December 2012, we received \$23.4 million of net proceeds from the sale of additional 2016 Notes. Funds received from the July 2011 common stock offering and offering of 2016 Notes were used to repay indebtedness under our prior credit facilities.

We believe that our cash flows from operations and cash on hand, including funds received from our equity and note offerings, are sufficient to support our liquidity needs for the next twelve months, including funding all of our current short-term objectives, including investments in planned infrastructure and deferred maintenance, recompletions, workovers and through-tubing plugbacks. We believe that our cash flows from operations and cash on hand will also be sufficient to pursue our current mid-term objectives relating to development of proved undeveloped opportunities. Our development of proved undeveloped opportunities is scalable. Depending upon the results of our short-term development initiatives, ongoing development efforts relating to our proved undeveloped opportunities and any further capital commitments, we may accelerate our planned development of proved undeveloped opportunities or otherwise adjust the nature or rate of our development program. Pursuit of our long-term plans for exploratory drilling of deep shelf prospects is expected to require funding in excess of our current resources and projected operating cash flow and to be dependent upon results attained by other operators that are currently pioneering ultra-deep drilling in the trend within which our ultra-deep prospects are located. At December 31, 2012, and as of March 2013, we were continuing to monitor developments within the ultra-deep trend and to be engaged in discussions with various potential partners relative to the potential exploration of our ultra-deep prospects. We presently lack the financial resources to carry our proportionate share of the anticipated exploration and development costs associated with such joint venture and will be required to secure additional financing to support our share of such costs and maintain our interest in such ultra-deep prospects. To that end, we expect to seek partners to enter into arrangements that will provide the necessary funding to pay some, or all, of our share of the joint venture costs with the effect of reducing our interest in the joint venture. We presently have no commitments to provide funding to cover our share of such costs.

Unexpected declines in commodity prices or production levels, or failures in achieving production increases through short- and mid-term development plans, could result in our inability to support our operations and drilling and development plans.

Further, as noted above, in order to further supplement our liquidity and increase our operating flexibility, we intend to enter into a new revolving credit facility. To that end, we continue to pursue efforts to secure a definitive agreement to provide a revolving credit facility but, as of this writing, have not yet established such a facility and there can be no assurance that we will be successful in establishing a revolving credit facility on terms that we consider to be favorable or at all.

Cash, Cash Flows and Working Capital

We had a cash balance of $32.3 million and working capital of $21.2 million at December 31, 2012 as compared to a cash balance of $15.9 million and working capital of $8.5 million at December 31, 2011. The change in cash on hand and working capital is primarily attributable to cash flows from operations supplemented by the receipt of proceeds from our 2012 placement of common stock and our December 2012 placement of additional 2016 Notes and partially offset by increased investment in our development program and losses arising from lost production in the wake of Hurricane Isaac.

Operations provided cash flow of $26.1 million during 2012 as compared to $33.8 million during 2011. The change in operating cash flows during 2012 was principally attributable to lost production due to the temporary shut-in of our wells in the wake of Hurricane Isaac.

Investing activities used cash flows of $56.3 million during 2012 as compared to $30.5 million used during 2011. The increase in cash used in investing activities during 2012 was attributable to acceleration of our development and drilling plans and investments in infrastructure projects.

Financing activities provided cash flows of $46.7 million during 2012 as compared to $8.1 million during 2011. Cash flows provided by financing activities during the 2012 reflected the receipt of funds from our 2012 equity offering ($18.4 million), short term notes payable issued for insurance premium finance ($1.7 million) and our 2012 offering of additional 2016 Notes ($23.4 million). Cash flows provided by financing activities during 2011 related to short-term notes payable issued for insurance premiums ($1.6 million), funds received from our April 2011 and July 2011 private placements of common stock and warrants ($34.8 million), all partially offset by retirement of indebtedness under our prior credit facilities and payments for insurance premiums. Cash flows from financing activities during 2011 reflects the net cash received from our July 2011 placement of equity but exclude proceeds from the equity placement and 2016 Note placement that were funded into escrow and applied directly to retire indebtedness.

The 2011 repayment of amounts owing under our prior credit facilities (totaling $145.2 million), including retirement of letter of credit obligations ($10.2 million), and the receipt of funds from the July 2011 equity placement and placement of 2016 Notes (each to the extent funded into escrow and applied to repayment of the indebtedness) were reported as noncash financing activities.

Debt

At December 31, 2012, we had $150.4 million of indebtedness outstanding, consisting of $152.5 million in face amount of 12.5% Senior Secured Notes due 2016 less $2.1 million of debt discount.

We had no letters of credit outstanding at December 31, 2012 that were not fully collateralized by cash.

As noted, in July 2011, we issued $127.5 million of our 2016 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 2016 Notes.

The 2016 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. The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

We have the option to redeem all or a portion of the 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture pursuant to which the 2016 Notes were issued plus accrued and unpaid interest. We may also redeem the 2016 Notes, in whole or in part, at a "make-whole" redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, we may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, we may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

Capital Expenditures

Our capital spending for 2012 was $59.8 million relating primarily to development of our oil and gas properties, including drilling 4 development wells, 12 recompletions, 16 workovers and investments in multiple infrastructure projects. Capital expenditures were up from $25.9 million during 2011.

As of March 15, 2013, we anticipate that our budget for drilling, recompletion and workover projects in 2013 will be approximately $40. 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.

In addition to our budgeted drilling, recompletion and workover projects, at March 15, 2013 we were evaluating a possible tubing replacement program and a facility upgrade program in Main Pass 25 each of which may entail capital expenditures on our part. We have initially identified up to 20 shut-in wells that are potential candidates for tubing replacement with the objective of gaining 20 barrels of oil equivalent production, or more, per day per well. Our initial estimate is that a program at that scale would cost approximately $200,000 per well. Commencement of a tubing replacement program remains subject to further analysis of shut-in well candidates, further quantification of estimated costs and potential production gains and other factors.

In Main Pass 25, we have verbally agreed to the broad outline of a program to upgrade our production handling capabilities at our facilities to accommodate the handing of production from the operator of a new discovery near our facilities. The facility upgrade, in addition to handling production from the operator, would be expected to allow us to bring production back to our facility that is currently handled at a nearby platform operated by a third party, potentially saving operating costs in the field and increasing potential production in the field due to decreases in line pressure. The operator in question has indicated a willingness to provide an oil-storage barge, separator and heater/treater but negotiations remain ongoing regarding the relative contributions and rights of the parties in connection with the potential upgrade of our Main Pass 25 facilities. Until negotiations regarding the Main Pass 25 upgrade are finalized, we are unable to estimate the amount of capital expenditures, if any, we will be required to make on such project.

Contractual Obligations

The following table details our long-term debt and contractual obligations as of December 31, 2012:

	Payments due by period				
	Total	2013	2014 – 2015	2016 – 2017	Thereafter
Debt [(1)]	$ 219,218,750	$ 19,062,500	$ 38,125,000	$ 162,031,250	$ —
Operating leases	78,972	78,972	—	—	—
Capital leases	—	—	—	—	—
Asset retirement obligations	51,887,000	256,000	2,520,000	5,685,000	43,426,000
Total	$ 271,184,722	$ 19,397,472	$ 40,645,000	$ 167,716,250	$ 43,426,000

(1) Debt consists of amounts owing under our 2016 Notes.

Risk Management Activities – Commodity Derivative Instruments

Due to the volatility of oil and natural gas prices and requirements under our prior revolving credit agreement, historically we periodically entered into price-risk management transactions (e.g., swaps, and floors) for a portion of our oil and natural gas production. In certain cases, this allowed us to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. The commodity derivative instruments applied to only a portion of our production, and provided only partial price protection against declines in oil and natural gas prices, and partially limited our potential gains from future increases in prices. None of these instruments were used for trading purposes.

During the first quarter of 2010, the administrative agent under our prior revolving credit agreement liquidated all of our commodity derivative instruments and applied the proceeds to indebtedness owed thereunder. During the third quarter of 2012, we reinstituted our hedging program.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2012.

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. During the quarter ended September 30, 2012, we resumed our hedging program under which, 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, 2012, we had the following crude oil hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Total Bbls	Net Unrealized Gain (Loss)
Swap	January 2013	March 2013	$ 108.00	67,500	$ (59,864)
Swap	January 2013	March 2013	106.00	22,500	(64,940)
Swap	January 2013	March 2013	$ 108.50	45,000	(46,282)
				135,000	$ (171,086)

Subsequent to December 31, 2012, we entered into additional crude oil swap contracts for the period April 2013 to March 2014 covering 500 to 1,000 barrels of oil per day at prices ranging from $106.82 to $109.20.

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 2012, we recorded an unrealized loss on commodity derivatives of $171,086 in accumulated other comprehensive income (loss).

Shell Trading (US) Company is the counterparty to each of our present forward physical contracts and fixed price swap contracts. 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 70 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, 2012 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 ineffective as of December 31, 2012.

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, 2012, 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, 2012. In order to remediate the material weakness, management will begin utilizing specialized software designed specifically to calculate ARO. This software will be implemented in the second quarter and used for the calculation of the Asset Retirement Obligation in 2013 and subsequent years.

The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by MaloneBailey LLP, an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2012, as stated in their report, which is included herein.

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 2012 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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Executive Officers

Our executive officers as of December 31, 2012, and their ages and positions as of that date, are as follows:

Name	Age	Position
Thomas F. Cooke	64	Chief Executive Officer and Chairman
Andrew C. Clifford	58	President
Michael Aldridge	54	Executive Vice President and Chief Financial Officer
Brian Daigle	53	Vice President – Operations
Randal McDonald, Jr.	55	Controller

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

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 33 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.

Michael Aldridge has served as our Executive Vice President and Chief Financial Officer since October 2011. Prior to joining our company, from 2000 to 2008, Mr. Aldridge served in various executive roles with Petroquest Energy, Inc., an NYSE-listed independent oil and gas company, including serving as Chief Financial Officer and a Director commencing in 2000, as Treasurer commencing in 2001 and as Executive Vice President commencing in 2006. From 2009 until joining our company, Mr. Aldridge served as a financial consultant to the energy industry. From 1992 to 1999, Mr. Aldridge served first as Vice President — Controller and then as Vice President — Corporate Communications for Ocean Energy, Inc., a public oil and gas exploration and development company. From 1991 to 1992, he served as Chief Financial Officer for Fleet Petroleum Partners, an independent exploration and production company. Prior to this, he served the oil and gas industry for eleven years with Ernst & Young LLP, where he attained the level of Senior Manager. Mr. Aldridge earned a Bachelor of Science in Accounting from Louisiana State University and is a Certified Public Accountant.

Brian Daigle has served as our Vice President – Operations since July 2010. Previously, Mr. Daigle served as Operations Manager of Harvest Oil and Gas, LLC and The Harvest Group, LLC (together, the "Harvest Companies") since 2006 and is responsible for the day-to-day management of the companies' physical assets. Prior to joining the Harvest Companies, from 2004 to 2006 Mr. Daigle was self-employed as a consultant to various operators providing operations management, technical support for facility installation, and managing daily production operations. Mr. Daigle served as Production Superintendent for Denbury Resources from 2001 to 2004. Mr. Daigle has more than 25 years of diversified experience in the oil and gas industry — focused on production operations, facility design, regulatory compliance, and project management in the Gulf of Mexico and inland waters of the State of Louisiana.

Randal McDonald, Jr. has 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.

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.

Item 11. Executive Compensation

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Equity compensation plan information is set forth in Part II, Item 5 of this Form 10-K.

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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See "Index to Financial Statements" on page 70 of this report.

2. Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference			Filed Herewith
		Form	Date Filed	Number	
2.1	Third Amended Plan of Reorganization of Saratoga Resources and its affiliated debtors, Modified March 31, 2010	10-K	04/14/10	2.1	
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	Registration Rights Agreement, dated July 12, 2011, by and among Saratoga Resources and Imperial Capital, LLC	8-K	07/15/11	4.2	
4.4	Form of Registration Rights Agreement, dated July 12, 2011, by and among Saratoga Resources and purchasers of common stock	8-K	07/15/11	4.3	
4.5	Registration Rights Agreement, dated December 4, 2012, by and among Saratoga Resources and Imperial Capital, LLC	8-K	12/05/12	4.2	
10.1	Form of Securities Purchase Agreement, dated April 2011	8-K	04/27/11	10.1	
10.2	Form of Warrant issued to Investors, dated April 2011	8-K	04/27/11	10.2	
10.3	Employment Agreement, dated October 9, 2007, with Thomas Cooke*	8-K	10/11/07	10.2	
10.4	Employment Agreement, dated October 8, 2007, with Andrew Clifford*	8-K	10/11/07	10.3	
10.5	Form of Securities Purchase Agreement, dated July 11, 2011, by and among Saratoga Resources and various purchasers of common stock	8-K	07/15/11	10.1	
10.6	Form of Securities Purchase Agreement, dated July 11, 2011, by and among Saratoga Resources and various purchasers of common stock	8-K	07/15/11	10.2	
10.7	Investor Rights Agreement, dated July 12, 2011	8-K	07/15/11	10.3	
10.8	Saratoga Resources, Inc. 2011 Omnibus Incentive Plan	S-8	09/13/11	10.1	
10.9	Form of Warrant Exercise Agreement	8-K	05/25/12	10.1	
10.10	Form of $8.00 Warrant	8-K	05/25/12	10.2	
10.11	Saratoga Resources, Inc. Annual Incentive Plan*	8-K	03/23/12	10.1	
10.12	Form of Share Purchase Agreement, dated May 14, 2012	8-K	05/16/12	10.1	
10.13	Form of Subscription Agreement, dated May 14, 2012	8-K	05/16/12	10.2	
10.14	Form of Registration Rights Agreement, dated May 2012	8-K	05/16/12	10.3	
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				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 1, 2013

By: /s/ Thomas F. Cooke
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 1, 2013
/s/ Andrew C. Clifford Andrew C. Clifford	President and Director	April 1, 2013
/s/ Kevin Smith Kevin Smith	Director	April 1, 2013
/s/ Rex H. White, Jr. Rex H. White, Jr.	Director	April 1, 2013
/s/ John W. Rhea, IV John W. Rhea, IV	Director	April 1, 2013
/s/ Michael Aldridge Michael Aldridge	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	April 1, 2013

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, 2012 and 2011, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity (deficit), and cash flows for the years ended December 31, 2012, 2011 and 2010. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Saratoga Resources, Inc. and its subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for the years ended December 31, 2012, 2011 and 2010, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Saratoga Resources, Inc.'s internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated April 1, 2013 expressed an adverse opinion thereon.

www.malone-bailey.com
Houston, Texas
April 1, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Saratoga Resources, Inc.
Houston, Texas

We have audited Saratoga Resources, Inc.'s (the "Company") internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, 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.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment. Management has identified a material weakness in controls related to the Company's accounting of asset retirement obligations. This material weakness was considered in determining the nature, timing and extent of audit tests applied in our audit of the 2012 consolidated financial statements of the Company, and this report does not affect our report on those financial statements.

In our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2012, based on the COSO Criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Saratoga Resources, Inc. as of December 31, 2012 and 2011, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity (deficit), and cash flows for the years ended December 31, 2012, 2011 and 2010, and our report dated April 1, 2013 expressed an unqualified opinion thereon.

www.malone-bailey.com
Houston, Texas
April 1, 2013

Saratoga Resources, Inc.
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32,302,313	$ 15,874,680
Accounts receivable	12,430,158	10,539,757
Prepaid expenses and other	1,268,971	1,189,406
Deferred tax asset, net	-	1,400,000
Other current assets	150,000	150,000
Total current assets	46,151,442	29,153,843
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	260,916,084	196,101,827
Other	795,138	658,113
	261,711,222	196,759,940
Less: Accumulated depreciation, depletion and amortization	(81,640,272)	(53,830,820)
Total property and equipment, net	180,070,950	142,929,120
Deferred tax asset, net	8,499,575	5,147,962
Other assets, net	19,929,394	20,531,218
Total assets	$ 254,651,361	$ 197,762,143
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 7,259,244	$ 4,598,534
Revenue and severance tax payable	6,129,867	5,709,773
Accrued liabilities	10,787,044	8,451,655
Derivative liabilities – short term	171,086	-
Short-term notes payable	373,360	344,256
Asset retirement obligation – current	256,200	1,548,945
Total current liabilities	24,976,801	20,653,163
Long-term liabilities		
Asset retirement obligation	16,815,736	9,852,920
Long-term debt, net of discount of $2,104,106 and $2,115,195, respectively	150,395,894	125,384,805
Total long-term liabilities	167,211,630	135,237,725
Commitment and contingencies (see notes)		
Stockholders' equity:		
Common stock, $0.001 par value; 100,000,000 shares authorized 30,905,101 and 26,714,815 shares issued and outstanding at December 31, 2012 and 2011, respectively	30,905	26,714
Additional paid-in capital	77,140,451	52,674,252
Accumulated other comprehensive loss	(171,086)	-
Retained earnings	(14,537,340)	(10,829,711)
Total stockholders' equity	62,462,930	41,871,255
Total liabilities and stockholders' equity	$ 254,651,361	$ 197,762,143

See notes to consolidated financial statements.

Saratoga Resources, Inc.
CONSOLIDATED STATEMENTS OF OPERATIONS AND OTHER COMPREHENSIVE INCOME(LOSS)

	For the Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil and gas revenues	$ 82,528,932	$ 76,159,268	$ 52,734,207
Oil and gas hedging	72,078	-	-
Other revenues	1,411,465	4,774,882	2,284,008
Total revenues	84,012,475	80,934,150	55,018,215
Operating Expense:			
Lease operating expense	19,317,283	17,123,890	13,774,406
Workover expense	3,828,197	2,666,600	2,154,482
Exploration expense	547,192	596,065	1,921,943
Loss on plugging and abandonment	2,468,969	393,599	-
Dry hole costs	93,353	3,912,823	-
Depreciation, depletion and amortization	27,407,700	15,591,048	16,001,826
Impairment expense	401,752	641,791	-
Accretion expense	1,510,165	1,672,900	1,668,268
Gain on revision of asset retirement obligations	(245,007)	(303,633)	-
Gain on purchase price adjustment	-	(1,426,778)	-
Loss on settlement of accounts payable	-	-	990,786
General and administrative	8,584,486	8,704,536	8,476,124
Severance taxes	7,768,426	6,090,666	5,214,677
Total operating expenses	71,682,516	55,663,507	50,202,512
Operating income	12,329,959	25,270,643	4,815,703
Other income (expense):			
Commodity derivative expense, net	-	-	696,550
Interest income	32,433	248,935	115,350
Interest expense	(17,651,496)	(17,947,784)	(22,584,934)
Financing expense	(7,527)	(837,364)	-
Gain on extinguishment of debt	-	7,708,486	-
Total other expense	(17,626,590)	(10,827,727)	(21,773,034)
Net income (loss) before reorganization expenses and income taxes	(5,296,631)	14,442,916	(16,957,331)
Reorganization expenses	161,416	436,092	2,198,359
Net income (loss) before income taxes	(5,458,047)	14,006,824	(19,155,690)
Income tax provision (benefit)	(1,750,418)	(6,839,117)	285,838
Net income (loss)	$ (3,707,629)	$ 20,845,941	$ (19,441,528)
Other Comprehensive income(loss)			
Unrealized loss on derivative instruments	(171,086)	-	-
Total comprehensive income (loss)	$ (3,878,715)	$ 20,845,941	$ (19,441,528)
Net income (loss) per share:			
Basic	$ (0.13)	$ 0.95	$ (1.14)
Diluted	$ (0.13)	$ 0.93	$ (1.14)
Weighted average number of common shares outstanding:			
Basic	29,378,542	21,975,480	16,996,166
Diluted	29,378,542	22,367,696	16,996,166

See notes to consolidated financial statements.

Saratoga Resources, Inc.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

	Common Stock		Additional Paid-in	Net Income	Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	(Loss)	(Loss)	Equity (Deficit)
Balance, December 31, 2009	16,690,292	$ 16,690	$ 19,887,814	$ (12,234,124)	$ -	$ 7,670,380
Common issued to vendors	483,306	483	990,302	-	-	990,785
Common issued for services	125,000	125	287,375	-	-	287,500
Fair value of warrants issued in connection with debt restructuring	-	-	4,099,116	-	-	4,099,116
Fair value of warrants issued for services	-	-	120,000	-	-	120,000
Stock-based employee compensation	-	-	2,162,644	-	-	2,162,644
Net loss	-	-	-	(19,441,528)	-	(19,441,528)
Balance, December 31, 2010	17,298,598	17,298	27,547,251	(31,675,652)	-	(4,111,103)
Common stock options exercised	118,354	118	43,082	-	-	43,200
Common stock warrants exercised	1,043,748	1,044	(1,044)	-	-	-
Common stock issued in private placement	8,254,115	8,254	34,761,844	-	-	34,770,098
Fair value of warrants cancelled in debt restructuring	-	-	(10,620,000)	-	-	(10,620,000)
Stock-based employee compensation	-	-	943,119	-	-	943,119
Net income	-	-	-	20,845,941	-	20,845,941
Balance, December 31, 2011	26,714,815	26,714	52,674,252	(10,829,711)	-	41,871,255
Common stock options exercised	208,599	209	405,047	-	-	405,256
Common stock warrants exercised	892,327	892	4,460,743	-	-	4,461,635
Common stock issued in private placement	3,089,360	3,090	18,394,490	-	-	18,397,580
Stock-based employee compensation	-	-	1,205,919	-	-	1,205,919
Other comprehensive loss	-	-	-	-	(171,086)	(171,086)
Net income	-	-	-	(3,707,629)	-	(3,707,629)
Balance, December 31, 2012	30,905,101	$ 30,905	$ 77,140,451	$ (14,537,340)	$ (171,086)	$ 62,462,930

See notes to consolidated financial statements.

Saratoga Resources, Inc.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ (3,707,629)	$ 20,845,941	$ (19,441,528)
Adjustments to reconcile net income (loss) to net cash used in operating activities:			
Depreciation, depletion, amortization and impairment	27,809,452	16,232,839	16,001,826
Accretion expense	1,510,165	1,672,900	1,668,268
Amortization of debt issuance costs and debt discount	1,304,362	2,228,909	2,492,390
Commodity derivative (income) expense	-	-	(473,962)
Dry hole costs	93,353	3,912,823	-
Stock-based compensation	1,205,919	943,119	2,570,144
Loss on settlement of accounts payable	-	-	990,786
Loss on plugging and abandonment	2,468,969	393,599	-
Gain on purchase price adjustment	-	(1,426,778)	-
Gain on revision of asset retirement obligations	(245,007)	(303,633)	-
Gain on extinguishment of debt	-	(7,708,486)	-
Deferred tax benefit	(1,951,613)	(6,547,962)	-
Changes in operating assets and liabilities:			
Accounts receivable	(1,890,401)	(1,499,920)	(1,660,182)
Prepaids and other	(79,565)	(150,688)	295,751
Accounts payable	180,923	(930,081)	(11,556,869)
Revenue and severance tax payable	420,094	641,443	(841,880)
Payments to settle asset retirement obligations	(3,062,625)	(1,148,655)	(153,655)
Accrued liabilities	2,002,499	6,689,890	8,742,502
Net cash provided (used) by operating activities	26,058,896	33,845,260	(1,366,409)
Cash flows from investing activities:			
Additions to oil and gas property	(57,096,363)	(29,347,415)	(9,417,471)
Additions to other property and equipment	(137,025)	(96,541)	(24,293)
Other assets	944,305	(1,028,048)	(767,381)
Net cash used by investing activities	(56,289,083)	(30,472,004)	(10,209,145)
Cash flows from financing activities:			
Issuance of warrants	-	-	100
Proceeds from issuance of common stock	23,264,470	14,813,298	-
Proceeds from short-term notes payable	1,685,226	1,649,068	1,260,276
Proceeds from long term debt	24,645,000	-	
Repayment of short-term notes payable	(1,656,122)	(1,590,110)	(1,389,234)
Repayment of debt borrowings	-	(268,224)	(5,500,000)
Repayment of debt borrowings - related party	-	(736,633)	-
Debt issuance costs of long term debt	(1,280,754)	(5,775,959)	-
Settlement of commodity hedges recorded in purchase accounting	-	-	38,913
Net cash provided (used) by financing activities	46,657,820	8,091,440	(5,589,945)
Net increase (decrease) in cash and cash equivalents	16,427,633	11,464,696	(17,165,499)
Cash and cash equivalents - beginning of period	15,874,680	4,409,984	21,575,483
Cash and cash equivalents - end of period	$ 32,302,313	$ 15,874,680	$ 4,409,984
Supplemental disclosures of cash flow information:			
Cash paid for income taxes	$ 201,195	$ 130,000	902,491
Cash paid for interest	8,011,117	8,210,196	10,537,405
Non-cash investing and financing activities:			
Unrealized loss on derivative instruments	(171,086)	-	-
Accounts payable for oil and gas additions	$ 2,479,787	$ 870,186	181,933
Accrued liabilities for oil and gas additions	332,891	124,712	280,556
Revisions to asset retirement obligations	4,572,244	1,542,172	281,389
Asset retirement obligations acquired	181,318	67,728	-
Accrued interest converted to long-term debt	-	-	30,811,843
Repayment of debt borrowing made directly to then existing lender by new lender and from proceeds from issuance of common stock		(145,231,776)	
Proceeds from issuance of long-term debt paid directly to then existing lender	-	125,231,775	
Proceeds from issuance of common stock paid directly to then existing lender	-	20,000,000	
Debt issuance costs from issuance of warrants	-	-	4,099,016

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 $161,416, $436,092 and $2,198,359 during the years ended December 31, 2012, 2011 and 2010, respectively.

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 with 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 natural gas 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, 2012 and 2011 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 $32.1 million and $15.6 million in excess of FDIC insured limits at December 31, 2012 and 2011, 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") accounted for 36%, 94% and 68% of our consolidated sales in 2012, 2011 and 2010, respectively. In addition, sales of oil and gas production to Plains Marketing and J. P. Morgan Ventures Energy Corp. accounted for 33% and 12%, respectively, of our consolidated sales in 2012. 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 (i) a net profits interest attributable to operating the Breton Sound 31 field, for which we receive a percentage of profits, (ii) production handling fees from our Vermilion 16 field and (iii) during the 2011 period, refunds of severance taxes under a Louisiana incentive program for previously inactive wells and purchase price adjustments.

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, 2012 and 2011, 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 to 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, 2012, 2011 and 2010 was $27,309,204, $15,461,056 and $15,863,307, 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, 2012, 2011 and 2010, Saratoga recorded impairment expense of $401,752, $641,791 and $0, respectively.

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 7 – "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.

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 5 – "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. 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 October 2012, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2012-04, "Technical Corrections and Improvements" in Accounting Standards Updated No. 2012-04. The amendments in this update cover a wide range of Topics in the Accounting Standards Codification. These amendments include technical corrections and improvements to the Accounting Standards Codification and conforming amendments related to fair value measurements. The amendments in this update will be effective for fiscal periods beginning after December 15, 2012. The adoption of ASU 2012-04 is not expected to have a material impact on our financial statements.

In February 2013, the FASB issued ASU No. 2013-02, amending Topic 220 – Comprehensive Income. ASU 2013-02 requires an entity to provide information in one location about amounts reclassified out of accumulated other comprehensive income by component and their corresponding effect on net income if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts not required to be reclassified to net income in their entirety, an entity is required to cross-reference to related footnote disclosures. The amendments in ASU 2013-02 will be required in interim reporting periods and are effective prospectively for the Company in the first quarter of 2013. The Company does not expect the adoption of this ASU to have a material impact on our financial statements.

NOTE 2. 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, 2012, 2011 and 2010, the Company incurred $161,416, $436,092 and $2,198,359, respectively in reorganization costs.

NOTE 3. OTHER ASSETS

Other assets consist of the following:

	December 31, 2012	December 31, 2011
Site specific trust accounts – P&A escrow	$ 5,279,084	$ 4,629,816
Debt issuance cost, net	5,728,755	5,386,274
Restricted cash – P&A bond	8,873,497	10,485,128
Other	48,058	30,000
	$ 19,929,394	$ 20,531,218

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 during 2012. See Note 8 – "Asset Retirement Obligations".

During the year ended December 31, 2011, it was discovered that certain Site Specific Trust Accounts which were in existence at the time of acquisition by Saratoga had not been reflected in the original purchase price accounting. Accordingly, the assets, totaling $1,426,778, were reflected in the balance sheet during the year and a corresponding gain on purchase price adjusted was recognized.

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, 2012 and 2011 reflect the issuance of the 2016 Notes in December 2012 and July 2011. See Note 4 – "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. In connection with the retirement of the debt to Wayzata Investment Partners ("Wayzata") in July 2011, the Company retired the letter of credit obligation and posted cash collateral in lieu of the letter of credit to secure the performance bond. See Note 8 – "Asset Retirement Obligations". The cash collateral is reflected as a long term asset to correspond with the expected timing of the related asset retirement obligation liability.

NOTE 4. DEBT

Long-term debt consists of the following:

	December 31, 2012	December 31, 2011
12.5% Senior Secured Notes due 2016	$ 152,500,000	$ 127,500,000
Less unamortized discount	(2,104,106)	(2,115,195)
	150,395,894	125,384,805

2016 Notes

In July 2011, the Company and the several wholly-owned subsidiaries of the Company (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 the Company's 12.5% Senior Secured Notes due 2016 (the "2016 Notes"). The 2016 Notes were sold at 98.221% of par. The 2016 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act. The 2016 Notes 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 Company's 2016 Notes. The 2016 Notes were sold at 98.58% of par. The 2016 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act. The 2016 Notes 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 2016 Notes were issued pursuant to an indenture, dated July 12, 2011 (the "Base Indenture"), among the Company, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee") and as collateral agent (the "Collateral Agent") and, with respect to the 2016 Notes issued in 2012, a First Supplemental Indenture, dated December 4, 2012 (the "Supplemental Indenture" and, together with the Base Indenture, the "Indenture"). The 2016 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.

The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

The 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 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest. The Company may also redeem the 2016 Notes, in whole or in part, at a "make-whole" redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, the Company may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, the Company may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

Retirement of Wayzata Debt

In July 2011, the Company utilized net proceeds from the issuance of long-term debt and common stock amounting to $125.2 million and $20.0 million, respectively, and $0.3 million in cash on hand to pay off the Wayzata debt of $145.5 million (including outstanding letter of credit obligations of $10.2 million).

In conjunction with the early payoff of amounts owing to Wayzata, the Wayzata 2010 Warrants to purchase 2,000,000 shares were cancelled. As a result of retirement of the Wayzata debt and cancellation of the Warrants, the Company wrote off $2.9 million of unamortized debt discount and debt issuance costs and reduced additional paid-in capital by $10.6 million (see Note 10 – "Common Stock – Warrant Activity") resulting in a net gain on the extinguishment of debt totaling $7.7 million.

NOTE 5. – 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 6 – "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. Our commodity derivative instruments are all with a single counterparty at December 31, 2012. 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, 2012, the Company had the following hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Total Bbls
Fixed Price Swap	January 2013	March 2013	$ 108.00	67,500
Fixed Price Swap	January 2013	March 2013	106.00	22,500
Fixed Price Swap	January 2013	March 2013	$ 108.50	45,000
				135,000

The following table presents the fair value of the Company's commodity derivative instruments at December 31, 2012 and 2011:

Description	December 31, 2012	December 31, 2011
Current liabilities:		
Commodity derivatives	$ 171,086	$ -
	$ 171,086	$ -

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, 2012, 2011 and 2010:

Description	For the Year Ended December 31, 2012	2011	2010
Realized mark-to-market gain	$ -	$ -	696,550
Total gain on commodity derivative instruments	$ -	$ -	696,550

Description	For the Year Ended December 31, 2012	2011	2010
Unrealized mark-to-market loss recognized in other comprehensive income (loss)	(171,086)	-	-
Total other comprehensive income (loss)	$ (171,086)	$ -	-

NOTE 6. – 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, 2012:

Description	Beginning Level 1	Ending Level 2	Fixed Level 3	Total
Liabilities:				
Commodity derivatives	$ -	$ 171,086	-	$ 171,086
	$ -	$ 171,086	-	$ 171,086

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 7. OIL AND GAS ASSETS

Property and equipment consisted of the following:

	December 31, 2012	December 31, 2011
Oil and gas properties (proved):		
Gross oil and gas properties (proved)	$ 260,916,084	$ 196,101,827
Accumulated depreciation, depletion, amortization and impairment	(81,056,770)	(53,345,814)
Net oil and gas properties (proved)	179,859,314	142,756,013
Other property and equipment	795,138	658,113
Accumulated depreciation and amortization	(583,502)	(485,006)
Net other property and equipment	211,636	173,107
Net property and equipment	$ 180,070,950	$ 142,929,120

At December 31, 2012, there were $1,233,800 in costs associated with wells in progress that were included in oil and gas properties, but were not yet included in the depletion calculation.

NOTE 8. 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, 2012 and 2011, the amount of the escrow account totaled $5.3 million and $4.6 million, respectively and is shown as other assets on the Company's balance sheet. See Note 3 – "Other Assets".

During the years ended December 31, 2012 and 2011, downward revisions in the asset retirement obligations relating to two properties exceeded the carrying amount of the property. According, during the years ended December 31, 2012 and 2011, respectively, the excess amounts, which were $245,007 and $303,633, were recognized as gains.

During the years ended December 31, 2012 and 2011, 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. In addition, several of the wells had unanticipated severe casing damage.. Accordingly, during the years ended December 31, 2012 and 2011, respectively, the excess amounts, which were $2,468,969 and $393,599, were recognized as losses.

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

Balance at December 31, 2009	10,190,073
Accretion expense	1,668,268
Additions	281,389
Revisions	-
Settlements	(153,655)
Balance at December 31, 2010	$ 11,986,075
Accretion expense	1,672,900
Additions	67,728
Revisions	(1,542,172)
Settlements	(782,666)
Balance at December 31, 2011	$ 11,401,865
Accretion expense	1,510,165
Additions	181,318
Revisions	4,572,244
Settlements	(593,656)
Balance at December 31, 2012	$ 17,071,936

NOTE 9. RELATED PARTY TRANSACTIONS

The Company had $8,137,500 and $10,159,128 as of December 31, 2012 and 2011 in cash collateral held in escrow by Macquarie Bank ("Macquarie") to assure maintenance and administration of performance bonds which secure certain plugging and abandonment obligations imposed by state law (see Note 3 – "Other Assets"). Macquarie affiliates own greater than 10% of the outstanding common stock of Saratoga.

Pursuant to our Plan of Reorganization, notes payable to the Company's Chief Executive Officer and President, in the aggregate amount of $736,633 were repaid in November 2011 upon prior satisfaction of all claims under the Plan of Reorganization, and following approval of the bankruptcy court.

NOTE 10. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

We have commitments under a non-cancellable operating lease agreement for our office in Houston, Texas.

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2012, 2011 and 2010 was $242,594, $226,258 and $210,349, 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, 2012, 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	**2013**	**2014 – 2015**	**2016 – 2017**	**Thereafter**
Debt	$ 219,218,750	$ 19,062,500	$ 38,125,000	$ 162,031,250	$ -
Operating leases	78,972	78,972	-	-	-
Capital leases	-	-	-	-	-
Asset retirement obligations	51,887,000	256,000	2,520,000	5,685,000	43,426,000
Total	$ 271,184,722	$ 19,397,472	$ 40,645,000	$ 167,716,250	$ 43,426,000

Contingencies

From time to time the Company may become involved in litigation in the ordinary course of business. At December 31, 2012, the Company's management was not aware, and as of the date of this report is not aware, other than as described below, of any such litigation that could have a material adverse effect on its results of operations, cash flows or financial condition.

In December 2009, the Parish of Plaquemines, State of Louisiana, filed supplemental assessments against multiple oil and gas companies, including Saratoga, for allegedly omitting or undervaluing oil producing assets on the annual self-reporting tax renditions used to calculate ad valorem taxes. In short, the difference between what was reported by the oil and gas companies and what the assessor taxed boiled down to how depreciation of the oil and gas related equipment was calculated and how certain equipment was classified. The amount alleged to be due by Saratoga for the years 2006, 2007, and 2008 is $1.3 million in Parish taxes. Also at issue are the increased assessment valuations for the years 2009, 2010, and 2011 brought by the Parish under the same theory. Saratoga is contesting the additional tax assessments in an action styled *Aviva America, Inc., The Harvest Group, LLC, Harvest Oil & Gas, LLC, Saratoga Resources, Inc., Lobo Operating, Inc. and Lobo Resources, Inc. v. Robert R. Gravolet, In His Capacity as Assessor for Plaquemines Parish, Louisiana*, 25th Judicial District Court for the Parish of Plaquemines, and, as to certain issues relating to such claim, a number of administrative proceedings before the Louisiana Tax Commission are also being fought. We believe the additional assessment is in error and intend to vigorously defend this action. Saratoga has paid $0.7 million of the additional assessments and has included the remaining $0.6 million of the $1.3 million total in accounts payable as of December 31, 2012 pending resolution of the dispute.

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, 2012, 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.

Registration Rights Agreements

In connection with the 2011 and 2012 issuance and sale of the 2016 Notes, we and the Guarantors entered into separate registration rights agreements (the "Registration Rights Agreements") with Imperial Capital. Pursuant to the Registration Rights Agreements, we and the Guarantors agreed to file registration statements with the Securities and Exchange Commission (the "SEC") so that holders of the 2016 Notes could exchange the 2016 Notes for registered notes that have substantially identical terms as the 2016 Notes. In addition, we and the Guarantors agreed to exchange the guarantee related to the 2016 Notes for a registered guarantee having substantially the same terms as the original guarantee. We and the Guarantors agreed to use reasonable best efforts to cause a registration statement with respect to the exchange to be filed within 90 days after the issuance of the 2016 Notes and declared effective under the Securities Act within 180 days after the issuance of the 2016 Notes. In the event of a failure to comply with our obligations to register the 2016 Notes within the specified time periods or to continue to maintain the effectiveness of the registration (a "Registration Default"), the interest rate on the 2016 Notes will be increased by 0.25% for each 90 days that such Registration Default continues, provided that the increase in interest rate shall in no event exceed an aggregate of 1.0% and provided, further, that upon cure of any such Registration Default the interest rate on the 2016 Notes will be reduced to its original rate. A registration statement relating to the exchange of the 2016 Notes issued during 2011 was filed on September 26, 2011 and was declared effective by the SEC on October 19, 2011. Following the effectiveness of the registration statement, we completed the exchange of registered notes for the unregistered 2016 Notes issued in 2011. A registration statement relating to the exchange of the 2016 Notes issued during 2012 was filed on January 11, 2013 and was declared effective by the SEC on February 6, 2013. Following the effectiveness of the registration statement, we completed the exchange of registered notes for the unregistered 2016 Notes issued in 2012.

In connection with the July 2011 issuance and sale of shares, we entered into a registration rights agreement (the "2011 Equity Registration Rights Agreement") with the purchasers of the shares. Pursuant to the 2011 Equity Registration Rights Agreement, the holders of a majority of the shares will have a demand registration right pursuant to which we may be required to file with the SEC one or more registration statements covering the resale of the shares. Additionally, the 2011 Equity Registration Rights Agreement provides "piggyback" registration rights to the holders of the shares pursuant to which the holders are entitled to notice of the filing of certain registration statements and inclusion of some or all of the shares in any such registration statements.

In connection with the 2012 issuance and sale of shares, we entered into a registration rights agreement (the "2012 Equity Registration Rights Agreement") with the purchasers of the shares. Pursuant to the 2012 Equity Registration Rights Agreement, we undertook to file a registration statement covering the shares not later than thirty days after the closing date of the offering. In the event that we failed to file the required registration statement within said thirty day period, failed to cause the registration statement to become effective within ninety days (120 days if the registration statement was subject to review by the SEC), failed to cause the shares to be listed for quotation on an approved market or otherwise fails to either maintain the continuing effectiveness of the registration statement or to make such filings with the SEC so as to permit resales under Rule 144, we agreed to pay as partial liquidated damages one percent of the aggregate purchase price of the shares for each thirty days in which such condition continues.

On June 20, 2012, we filed a registration statement covering the resale of, among other shares, the shares covered by the 2011 Equity Registration Rights Agreement and the 2012 Equity Registration Rights Agreement. That registration statement was declared effective by the SEC on July 5, 2012.

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,		
	2012	2011	2010
Income (loss) attributable to common stock	$ (3,707,629)	$ 20,845,941	$ (19,441,528)
Weighted average number of shares outstanding, basic	29,378,542	21,975,480	16,996,166
Incremental shares from assumed conversion of dilutive stock options and warrants	-	392,216	-
Weighted average number of shares outstanding, diluted:	29,378,542	22,367,696	16,996,166
Net Income (loss) per share, basic	(0.13)	0.95	(1.14)
Net Income (loss) per share, diluted	(0.13)	0.93	(1.14)
Number of antidilutive stock options and warrants excluded from calculation above	416,188	-	4,198,016

Common Stock Activity

Pursuant to the terms of the Company's plan of reorganization, in May 2010, the Company issued an aggregate of 483,306 shares of common stock pro rata among oil lien claim creditors, other secured creditors and unsecured creditors. The Company recorded a loss on settlement of accounts payable in the income statement for $990,785 for the fair value of the common stock.

During the year ended December 31, 2011, the Company issued an aggregate of 118,354 shares of common stock upon the exercise of outstanding stock options by former employees. Of the shares issued, 45,000 shares were issued for gross proceeds of $43,200, or $0.96 a share, and 73,354 shares were issued pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price of 183,333 stock options, with a weighted average exercise price $2.77 per share. See "-Stock Option Activity" below.

During the year ended December 31, 2011, the Company issued an aggregate of 1,043,748 shares of common stock upon the exercise of outstanding warrants. All of the shares were issued pursuant to "cashless" exercise provisions wherein the intrinsic value of the warrants were delivered to the Company in lieu of cash payment of the exercise price of 1,055,516 warrants, with a weighted average exercise price $0.06 per share. See "-Warrant Activity" below.

In April 2011, the Company sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 2,481,316 shares of common stock and warrants to purchase 1,240,658 shares of common stock. The shares and warrants were offered in units of two shares and one warrant at $6.00 per unit for aggregate gross proceeds of $7,443,948. Pursuant to the offering, the Company issued 84,600 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

In July 2011, the Company sold to U.S. and non-U.S. accredited and institutional investors, in a private placement, an aggregate of 5,650,000 shares of common stock at a price of $5.00 per share. Net proceeds from the sale of shares were approximately $27.3 million, of which $20.0 million was deposited directly into a third party escrow account to be applied to the retirement of indebtedness to Wayzata. Pursuant to the offering, the Company issued 38,200 shares of common stock to a placement agent with respect to shares sold to non-U.S. investors.

During the year ended December 31, 2012, the Company issued an aggregate of 208,599 shares of common stock upon the exercise of outstanding stock options by individuals, including two non-executive employees and a non-employee director. Of the shares issued, 163,500 shares were issued for gross proceeds of $405,256, or $2.48 a share, and 45,099 shares were issued pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price of 70,000 stock options, with a weighted average exercise price $2.38 per share. See "-Stock Option Activity" below.

During the year ended December 31, 2012, the Company issued an aggregate of 892,327 shares of common stock upon the exercise of outstanding warrants for which the Company received $4,461,635 of proceeds, or $5.00 per share. In conjunction with the exercise of 213,996 of those warrants, the Company granted three year warrants to purchase an aggregate of 106,997 shares of common stock at $8.00 per share. See "-Warrant Activity" below.

On May 24, 2012, the Company sold, in a private placement, an aggregate of 3,089,360 shares of common stock to certain institutional and accredited investors at a price of $6.25 per share, for net proceeds of approximately $18.4 million.

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"). As of December 31, 2012, no awards were outstanding under the 2008 Plan or the 2006 Plan.

Stock Option Activity

In April 2010, the Company's board of directors approved stock option grants to purchase an aggregate of 845,000 shares of common stock to the Company's directors and to various key employees, including an aggregate of 50,000 stock options granted to directors and 150,000 stock options granted to an officer of the Company. 330,000 of the options granted in April 2010 were forfeited during 2010. The grant date value of the aggregate 845,000 options was $2,535,000, which includes the grant date value of the 330,000 options forfeited of $990,000. The options are exercisable at $3.00 per share for a term of ten years. The options are subject to different vesting periods. The options were valued using the Black-Sholes model with the following assumptions: $3.00 quoted stock price; $3.00 exercise price; 352% volatility; 5 to 6 year estimated life; zero dividends; 2.61% discount rate.

In July 2010, the Company granted stock options to purchase 115,000 shares of common stock to employees, including 40,000 options granted to an officer. The options are exercisable at $1.53 per share for a term of ten years and vest ratably over three years. The grant date value of the options was $175,950. The options were valued using the Black-Scholes model with the following assumptions: $1.53 quoted stock price; $1.53 exercise price; 345% volatility; 5.8 year estimated life; zero dividends; and 2.12% discount rate.

In July 2010, the Company granted stock options to purchase 120,000 shares of common stock to employees, including 100,000 options granted to an officer. The options are exercisable at $1.71 per share for a term of ten years and vest ratably over three years. The grant date value of the options was $205,200, which includes the grand date value of 20,000 options forfeited of $34,200. The options were valued using the Black-Scholes model with the following assumptions: $1.71 quoted stock price; $1.71 exercise price; 344% volatility; 6 year estimated life; zero dividends; and 2.1% discount rate.

In July 2010, the Company granted stock options to purchase 202,500 shares of common stock to consultants. The options are exercisable at $1.71 per share for a term of five years. 2,500 of the options were granted to a consultant for investor relations and vested on the date of grant. 200,000 of the stock options were granted to a consultant for business development services of which 10,000 vested on grant date. The remaining 190,000 options vest as follows: (i) 2,000 options vest each month from August 2010 to December 2010; (ii) 80,000 options vest based on satisfaction of certain performance criteria, and (iii) 25,000 options vest on each of June 30, 2011, December 31, 2011, December 31, 2012 and December 31, 2013 provided that the consultant continues to provide services to the Company as of those dates. The grant date value of the options was $61,070. The options were valued using the Black-Scholes model with the following assumptions: $1.71 quoted stock price; $1.71 exercise price; 344% volatility; 2 to 3 year estimated life; zero dividends; and 0.98% discount rate.

In August 2010, the Company granted stock options to purchase 10,000 shares of common stock to a consultant. The options are exercisable at $1.39 per share for a term of five years and vest in full on February 28, 2011. The grant date value of the options was $13,800. The options were valued using the Black-Scholes model with the following assumptions: $1.39 quoted stock price; $1.39 exercise price; 340% volatility; 2.5 year estimated life; zero dividends; and 0.98% discount rate.

In March 2011, the Company's board of directors approved stock option grants to purchase an aggregate of 105,000 shares of common stock to the Company's non-employee directors, including options granted to a newly appointed director. 70,000 of the options are exercisable at \$3.05 per share and 35,000 of the options are exercisable at \$2.80 per share. The options vested 50% on the respective grant dates and vest as to the remaining 50% one year from the grant date. The options are exercisable for a term of seven years. The grant date value of the aggregate 105,000 options was \$0.3 million. The options were valued using the Black-Scholes model with the following assumptions: 346% - 347% volatility; 3.75 year estimated life; zero dividends; 1.394% discount rate as to 35,000 options and 1.64% discount rate as to 70,000 options; quoted stock price and exercise price of \$2.80 per share as to 35,000 options and \$3.05 per shares as to 70,000 options.

In April 2011, the Company's board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a non-executive employee. The options are exercisable for a term of ten years at \$2.75 per share and vest 1/3 on each of the first three anniversaries of the grant date. The grant date value of the options was \$82,500. The options were valued using the Black-Scholes model with the following assumptions: 320% volatility; 6.0 year estimated life; zero dividends; 2.47% discount rate; and, quoted stock price and exercise price of \$2.75.

In September 2011, the Company's board of directors approved a stock option grant to purchase an aggregate of 50,000 shares of common stock to a newly hired non-executive employee. The options are exercisable for a term of seven years at \$5.63 per share and vest as to 16,000 shares on the first anniversary of the grant date and as to 17,000 shares on each of the second and third anniversaries of the grant date. The grant date value of the options was \$281,500. The options were valued using the Black-Scholes model with the following assumptions: 318% volatility; 6.0 year estimated life; zero dividends; 1.19% discount rate; and, quoted stock price and exercise price of \$5.63.

In October 2011, the Company's board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a newly hired non-executive employee. The options are exercisable for a term of seven years at \$5.11 per share and vest as to 10,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was \$153,300. The options were valued using the Black-Scholes model with the following assumptions: 309% volatility; 4.5 year estimated life; zero dividends; 0.96% discount rate; and, quoted stock price and exercise price of \$5.11.

In October 2011, the Company's board of directors approved a stock option grant to purchase an aggregate of 150,000 shares of common stock to a newly hired executive employee. The options are exercisable for a term of seven years at \$4.59 per share and vest as to 50,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was \$687,750. The options were valued using the Black-Scholes model with the following assumptions: 307% volatility; 4.5 year estimated life; zero dividends; 0.99% discount rate; and, quoted stock price and exercise price of \$4.59.

In November 2011, the Company's board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a newly hired executive employee. The options are exercisable for a term of seven years at \$4.62 per share and vest as to 10,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was \$138,600. The options were valued using the Black-Scholes model with the following assumptions: 305% volatility; 4.5 year estimated life; zero dividends; 0.91% discount rate; and, quoted stock price and exercise price of \$4.62.

In December 2011, a former employee exercised stock options to purchase 150,000 shares of common stock at \$3.00 per share and stock options to purchase 33,333 shares of common stock at \$1.71 per share. The stock options were exercised pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 73,354 shares of common stock pursuant to the exercise of the stock options.

During the year ended December 31, 2011, stock options to purchase 45,000 shares of common stock at prices ranging from \$0.36 to \$1.71 were exercised for cash proceeds totaling \$43,200.

In January 2012, a non-executive employee exercised stock options to purchase 10,000 shares of common stock at \$3.00 per share. The stock options were exercised pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 5,275 shares of common stock pursuant to the exercise of the stock options.

In March 2012, the Company's board of directors approved a stock option grant to purchase an aggregate of 5,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at \$6.40 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 \$31,850. The options were valued using the Black-Scholes model with the following assumptions: 296% volatility; 3.75 year estimated life; zero dividends; 0.64% discount rate; and, quoted stock price and exercise price of \$6.40.

In April 2012, a non-executive employee exercised stock options to purchase 25,000 shares of common stock at $1.53 per share. The stock options were exercised pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 19,650 shares of common stock pursuant to the exercise of the stock options.

In May 2012, a non-employee director exercised stock options to purchase 35,000 shares of common stock at $2.80 per share. The stock options were exercised pursuant to "cashless" exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 20,174 shares of common stock pursuant to the exercise of the stock options.

In June 2012, the Company's board of directors approved stock option grants 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 $6.65 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 $695,100. The options were valued using the Black-Scholes model with the following assumptions: 292% volatility; 3.75 year estimated life; zero dividends; 0.50% discount rate; and, quoted stock price and exercise price of $6.65.

During the year ended December 31, 2012, stock options to purchase 163,500 shares of common stock at prices ranging from $1.53 to $3.00 were exercised for cash proceeds totaling $405,255.

Stock based compensation expense attributable to common shares and grants of options was $1,205,919, $943,119 and $2,570,145 during the years ended December 31, 2012, 2011 and 2010, respectively. The unamortized amount of stock-based compensation that had not been recorded was $517,646 and $1,226,285 as of December 31, 2012 and 2011, respectively.

The following table presents the options outstanding at December 31, 2012:

	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, 2009	75,000	0.36	0.18	8.2	141,750
Granted	1,292,500	2.53	2.53	8.6	265,550
Exercised	-	-	-	-	-
Forfeited	(350,000)	1.64	2.93	-	-
Outstanding at December 31, 2010	1,017,500	$ 2.24	$ 2.23	8.3	$ 407,300
Granted	395,000	4.19	4.19	7.2	1,228,350
Exercised	(228,333)	2.41	2.36	-	-
Forfeited	(201,667)	1.71	1.48	-	-
Outstanding at December 31, 2011	982,500	$ 3.09	$ 3.07	7.6	$ 4,133,025
Granted	110,000	6.64	6.61	0.6	-
Exercised	(233,500)	2.45	2.38	-	-
Forfeited	(75,000)	4.26	4.26	-	-
Outstanding at December 31, 2012	784,000	3.66	3.65	6.5	474,240
Exercisable at December 31, 2012	555,666	$ 3.20	$ 3.19	6.6	$ 431,639

(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 warrant. On December 31, 2012, the last reported sales price of our common stock on the NYSE MKT was $3.54 per share.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2012:

	Options Outstanding and Exercisable		
Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (in Years)
$ 0.36	50,000	$ 0.03	0.6
1.39	10,000	0.03	0.1
1.53	33,166	0.09	0.5
1.71	2,500	0.01	-
2.75	10,000	0.05	0.2
2.80	35,000	0.18	0.3
3.00	255,000	1.38	3.3
3.05	35,000	0.19	0.3
4.59	50,000	0.41	0.5
4.62	10,000	0.08	0.1
5.11	10,000	0.09	0.1
6.40	2,500	0.03	-
6.65	52,500	0.63	0.6
	555,666	$ 3.20	6.6

Warrant Activity

In April 2010, the Company sold to a service provider, for a purchase price of $100, a warrant to purchase 40,000 shares of the Company's common stock. The grant date value of the warrants was $120,000 and recorded as legal expense. The warrants are exercisable at $3.00 per share for a term of five years and are vested immediately. The warrants were valued using the Black-Scholes model with the following assumptions: $3.00 quoted stock price; $3.00 exercise price; 352% volatility; 5 year estimated life; zero dividends; 2.61% discount rate.

Pursuant to the terms of the Company's plan of reorganization, in May 2010, the Company issued to Wayzata a warrant (the "Wayzata 2010 Warrants") to purchase 2,000,000 shares of common stock. The warrants vested as to 111,111 shares on exit from bankruptcy (May 14, 2010) and, thereafter, vested as to 111,111 shares per month until April 2012. The fair value of the warrants of $4,099,116 was recorded as a debt discount to long-term debt. The warrants were exercisable at $0.01 per share for a term of five years. The warrants were valued using the Black-Scholes model with the following assumptions: $2.05 quoted stock price; $0.01 exercise price; 397% volatility; 5 year estimated life; zero dividends; 0.85% discount rate.

In April 2011, the Company entered into a Warrant Termination Agreement with Wayzata. Under the terms of the Warrant Termination Agreement, Wayzata agreed, subject to the Company's repayment by July 14, 2011 of all amounts owing under the existing credit facilities with Wayzata, to the cancellation of the Wayzata 2010 Warrants. Upon closing of the July 2011 note placement and retirement of all amounts owing to Wayzata, in July 2011, the Wayzata 2010 Warrants were cancelled resulting in a gain of $10.6 million relating to the unamortized balance of the fair value of the warrants (see Note 4 – "Debt – Retirement of the Wayzata Debt").

Pursuant to the April 2011 private placement of units of common stock and warrants, the Company issued warrants to purchase 1,240,658 shares of common stock. The warrants are exercisable for two years to purchase shares of common stock at $5.00 per share. In connection with the private placement, the company issued to a placement agent a warrant to purchase 42,300 shares of common stock on identical terms to the warrants sold in the private placement.

In September 2011, Wayzata exercised a warrant, originally issued in July 2008, to purchase 805,516 shares of common stock at $0.01 per share. The warrant was exercised pursuant to a "cashless" exercise provision wherein the intrinsic value of the warrant was delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 803,764 shares of common stock pursuant to the exercise of the warrant.

In December 2011, a service provider exercised a warrant, originally issued in May 2008, to purchase 250,000 shares of common stock at $0.25 per share. The warrant was exercised pursuant to a "cashless" exercise provision wherein the intrinsic value of the warrant was delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 239,984 shares of common stock pursuant to the exercise of the warrant.

In January 2012, an investor exercised a warrant, originally issued in April 2011, to purchase 500,000 shares of common stock at $5.00 per share for proceeds of $2,500,000.

In May 2012, investors exercised warrants, originally issued in April 2011, to purchase 213,996 shares of common stock at $5.00 per share for proceeds of $1,069,980. In conjunction with the exercise of these warrants, the Company granted three year warrants to purchase an aggregate of 106,997 shares of common stock at $8.00 per share.

In June and July 2012, investors exercised warrants, originally issued in April 2011, to purchase 178,331 shares of common stock at $5.00 per share for proceeds of $891,655.

The following table presents the warrants outstanding at December 31, 2012:

	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, 2009	1,090,516	0.08	1.99	2.5	2,370,506
Granted	2,040,000	0.07	2.07	4.3	4,480,000
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at December 31, 2010	3,130,516	$ 0.07	$ 2.03	3.7	$ 6,850,506
Granted	1,282,958	5.00	2.66	1.4	2,950,803
Exercised	(1,055,516)	0.07	2.01	-	-
Forfeited	(2,000,000)	0.01	2.05	-	-
Outstanding at December 31, 2011	1,357,958	$ 4.82	$ 2.61	1.4	$ 3,365,703
Granted	106,997	8.00	6.20	0.4	-
Exercised	(892,327)	5.00	2.65	-	-
Forfeited	-	-	-	-	-
Outstanding at December 31, 2012	572,628	$ 5.14	$ 3.22	0.8	$ 132,900
Exercisable at December 31, 2012	572,628	$ 5.14	$ 3.22	0.8	$ 132,900

(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, 2012, the last reported sales price of our common stock on the NYSE MKT was $3.54 per share.

The following table summarizes information about stock warrants outstanding and exercisable at December 31, 2012:

Warrants Outstanding and Exercisable			
Exercise Price	Number of Shares Underlying Warrants	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (in Years)
$ 0.17	30,000	$ 0.01	-
1.50	5,000	0.01	-
3.00	40,000	0.21	0.2
5.00	390,631	3.41	0.2
8.00	106,997	1.50	0.4
	572,628	$ 5.14	0.8

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, 2012 and 2011 consisted of the following:

	2012	2011
Current:		
Federal	$ 87,513	$ -
State	113,682	(291,155)
	201,195	(291,155)
Deferred:		
Federal	(1,951,613)	(6,547,962)
State	-	-
	(1,951,613)	(6,547,962)
Total tax provision (benefit)	$ (1,750,418)	$ (6,839,117)

The U.S. federal statutory income tax rate is reconciled to the effective rate at December 31, 2012 and 2011 as follows:

	2012	2011
Income tax expense at U.S. federal statutory rate	35.0 %	35.0 %
Valuation allowance	-	(69.9)%
State and local income taxes, net of federal income tax benefit	-	3.3 %
Permanent differences	(1.0)%	(20.1)%
Temporary differences	(1.9)%	2.6 %
Effective tax rate	32.1 %	(49.1)%

The components of the net deferred tax assets (liabilities) at December 31, 2012 and 2011 are as follows:

	2012	2011
Deferred tax asset		
Net operating loss	$ 15,603,753	$ 8,152,044
Stock-based compensation	2,379,770	1,918,506
Debt issuance cost (amortization)	1,360,620	1,309,041
Depreciation and amortization	(25,671)	8,971
Capital loss carryover	103,752	103,752
Charitable contributions	15,942	7,048
Total deferred tax assets	19,438,166	11,499,362
Deferred tax liability		
Depletion on oil and gas properties	10,938,591	4,951,400
Total deferred tax liabilities	10,938,591	4,951,400
Less: valuation allowance	-	-
Deferred tax asset (liability)	$ 8,499,575	$ 6,547,962

At December 31, 2012, we had $40.8 million of federal net operating loss, or NOL, carryforwards; the federal NOL carryforwards have expiration dates through the year 2032.

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. As of December 31, 2011, we removed substantially all deferred tax valuation allowances related to net operating loss carryforwards.

NOTE 13. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION - UNAUDITED

Supplemental quarterly financial information is as follows:

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2012				
Total revenues	$ 20,217,928	$ 24,113,983	$ 16,717,445	$ 22,963,119
Net income (loss)	(1,219,074)	860,285	(475,003)	(2,873,837)
Net income (loss) per share, basic	(0.04)	0.03	(0.02)	(0.10)
Net income (loss) per share, diluted	$ (0.04)	$ 0.03	$ (0.02)	$ (0.10)
2011				
Total revenues	$ 16,947,038	$ 21,056,204	$ 19,824,335	$ 23,106,573
Net income (loss)	358,237	2,068,902	6,171,918	12,246,884
Net income (loss) per share, basic	0.02	0.11	0.25	0.57
Net income (loss) per share, diluted	$ 0.02	$ 0.09	$ 0.24	$ 0.58
2010				
Total revenues	$ 12,691,034	$ 13,682,755	$ 13,678,410	$ 14,966,016
Net income (loss)	(5,833,834)	(8,363,373)	(3,523,767)	(1,720,554)
Net income (loss) per share, basic	(0.35)	(0.49)	(0.21)	(0.09)
Net income (loss) per share, diluted	$ (0.35)	$ (0.49)	$ (0.21)	$ (0.09)

NOTE 14. SUPPLEMENTAL OIL AND GAS DISCLOSURES - UNAUDITED

Capitalized costs for our oil and gas producing activities consisted of the following at December 31, 2012 and 2011:

	2012	2011
Proved properties	$ 260,916,084	$ 196,101,827
Unproved properties	-	-
	260,916,084	196,101,827
Accumulated depreciation, depletion, amortization and impairment	(81,056,770)	(53,345,814)
Net capitalized costs	$ 179,859,314	$ 142,756,013

Costs incurred for oil and gas property acquisitions, exploration and development for the years ended December 31, 2012 and 2011 are as follows:

	2012	2011
Acquisitions of properties:		
Proved	$ -	$ 569,425
Unproved	-	-
Exploration and dry hole costs	640,545	4,508,888
Development	59,815,686	25,898,062
	$ 60,456,231	$ 30,976,375

The following table sets forth the consolidated results of operations for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
Oil and gas revenues	$ 82,528,932	$ 76,159,268	$ 52,734,207
Lease operating expense	(19,317,283)	(17,123,890)	(13,774,406)
Workover expense	(3,828,197)	(2,666,600)	(2,154,482)
Exploration expense	(547,192)	(596,065)	(1,921,943)
Loss on plugging and abandonment	(2,468,969)	(393,599)	-
Dry hole costs	(93,353)	(3,912,823)	-
Depreciation, depletion, amortization and impairment	(27,809,452)	(16,232,839)	(16,001,826)
Accretion expense	(1,510,165)	(1,672,900)	(1,668,268)
Gain on revision of asset retirement obligations	245,007	303,633	-
Severance taxes	(7,768,426)	(6,090,666)	(5,214,677)
Income before income taxes	19,430,902	27,773,519	11,998,605
Income tax benefit (provision)	1,750,418	6,839,117	(285,838)
Results of operations for oil and gas producing activities (excluding Corporate overhead and financing costs)	$ 21,181,320	$ 34,612,636	$ 11,712,767

Proved Oil and Gas Reserves

Proved oil and gas reserves were estimated by independent petroleum engineers. The reserves were based on the following assumptions:

- 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.
- Production and development costs were computed using year-end costs assuming no change in present economic conditions.
- 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 three-year period ended December 31, 2012:

	Gas (Mcf)	Oil (Bbls)	Boe
For the year ended December 31, 2010			
Beginning of year	62,247,900	7,578,100	17,952,751
Acquisition of reserves	887,679	252,047	399,994
Discoveries and extensions	-	-	-
Improved recovery	-	-	-
Revisions	(377,179)	598,253	535,390
Production	(1,882,800)	(550,000)	(863,800)
End of year	60,875,600	7,878,400	18,024,335
Proved developed reserves			
Beginning of year	9,387,400	2,984,800	4,549,367
End of year	5,112,400	2,656,600	3,508,667
For the year ended December 31, 2011			
Beginning of year	60,875,600	7,878,400	18,024,335
Acquisition of reserves	1,717,000	172,900	459,067
Discoveries and extensions	1,456,000	18,400	261,067
Improved recovery	-	-	-
Revisions	3,951,000	511,200	1,169,700
Production	(2,038,000)	(605,900)	(945,567)
End of year	65,961,600	7,975,000	18,968,602
Proved developed reserves			
Beginning of year	5,112,400	2,656,600	3,508,667
End of year	10,101,000	2,580,600	4,264,100
For the year ended December 31, 2012			
Beginning of year	65,961,600	7,975,000	18,968,602
Acquisition of reserves	-	-	-
Discoveries and extensions	-	-	-
Improved recovery	-	-	-
Revisions	(10,403,800)	1,108,000	(625,968)
Production	(2,639,500)	(676,400)	(1,116,317)
End of year	52,918,300	8,406,600	17,226,317
Proved developed reserves			
Beginning of year	10,101,000	2,580,600	4,264,100
End of year	9,159,500	2,809,200	4,335,783

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)	2012	2011	2010
Future cash inflows	$ 1,102,848	$ 1,210,125	$ 934,061
Future production costs	(258,251)	(281,429)	(209,593)
Future development costs	(232,806)	(226,552)	(239,510)
Future net cash flows before income taxes	611,791	702,144	484,958
Future income tax expense	(171,671)	(207,555)	(130,490)
Future net cash flows before 10% discount	440,120	494,589	354,468
10% annual discount for estimating timing of cash flows	(147,435)	(163,705)	(118,811)
Standardized measure of discounted future net cash flows	$ 292,685	$ 330,884	$ 235,657

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)	2012	2011	2010
Beginning of year	$ 330,884	$ 235,657	$ 145,586
Sales of oil and gas produced, net of production costs	(51,615)	(49,945)	(31,270)
Net change in prices and production costs	(2,218)	108,942	135,389
Extension, discoveries, and improved recovery, less related costs	-	16,128	-
Development costs incurred during the year	20,993	7,088	-
Net change in estimated future development costs	(19,437)	7,493	(49,840)
Revisions of previous quantity estimates	(20,211)	37,107	13,943
Net change from acquisitions of minerals in place	-	16,861	3,689
Net change in income taxes	19,232	(53,119)	(1,919)
Accretion of discount	46,431	31,597	22,398
Changes in timing and other	(31,374)	(26,925)	(2,319)
End of year	$ 292,685	$ 330,884	$ 235,657

NOTE 15. SUBSEQUENT EVENTS

In January 2013, the Company received gross proceeds of $9,945 for 6,500 stock options exercised at $1.53 a share.

In January 2013, the Company entered into a fixed price hedge agreement with Cargill, Incorporated for a total of 159,500 barrels of crude oil at $109.20 per barrel for the period from April 2013 through March 2014.

In January 2013, the Company entered into a fixed price hedge agreement with Koch Supply & Trading, LP for a total of 122,500 barrels of crude oil at $106.82 per barrel for the period from April 2013 through December 2013.

In March 2013, the Company bid on, and was the apparent high bidder relative to, 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. Final award of the leases is subject to BOEMRE review. Lease bonuses on the prospects total $880,000 and first year annual rentals of $138,698. Additionally, assuming final award of the leases, the Company will pay a prospect fee of $450,000 to a third party consultant.

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SARATOGA RESOURCES, INC.

Declines in gas reserves accounted for all of our reduction in reserves at year end with oil reserves increasing during 2012.

Roughly half of our negative revisions to reserves was attributable to lower natural gas pricing. Aside from pricing, changes in our reserves reflect a combination of production, new reserve adds through the drill bit and revisions resulting from both drilling and field studies. We had 950 MBOE (59% oil) positive 1P reserve revisions due to field studies at Breton Sound 32 and Grand Bay plus a further 671 MBOE 2P and 348 MBOE 3P. We also had 517 MBOE (all oil) positive 1P reserve revisions due to drilling at North Tiger, Jupiter and Buddy but offset by 2,637 MBOE (94% gas) negative 1P revisions due to thin sands in our Mesa Verde well.

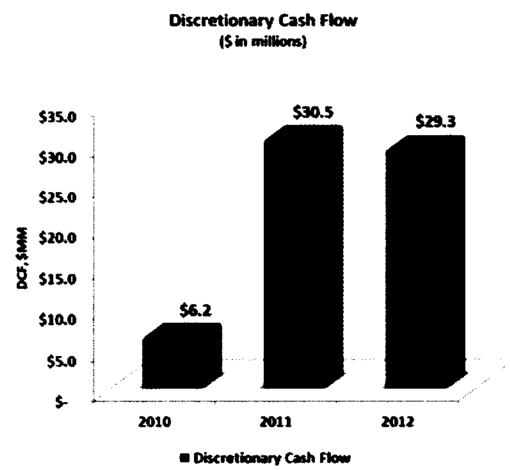
Our field studies are continuing to upgrade the quality of our reserves and to unlock more impactful opportunities, including promising horizontal well opportunities that we expect to pursue beginning in 2013. We seek a balance between oil and gas, especially as we see natural gas prices improving, and are pleased with our present 49% oil versus gas reserve mix.

De-Risking Commodity Prices: Beginning late in 2012, we reinstituted our hedging program to minimize exposure to commodity price risk. To date, our hedging program has focused on oil but we are encouraged by recent natural gas price movements and are monitoring opportunities to layer in gas hedges. We currently have hedged an average of 814 BOPD at an average price of $108.10 through Q1 2014. We are constantly evaluating further hedging in oil and natural gas.

2012 Results: We produced a total of 1,116 MBOE in 2012, up 18% from 2011, with 61% of 2012 production being oil. Oil and gas revenues increased by 8% from 2011. The gains in production and oil and gas revenues were in spite the effects of Hurricane Isaac.

We were able to reduce recurring LOE per BOE by more than 4% and we continue to aggressively look at controlling costs and expect that some of the one-time events that negatively affected 2012 results will be behind us.

While we no doubt faced challenges that hurt our operating results during 2012, we did manage to generate a respectable $29.3 million of discretionary cash flow, or $1.00 per share, during the year.



Despite the operating challenges incurred during 2012, we ended the year in a solid position with $32.3 million of cash and $8.5 million of working capital on hand at year-end, and we anticipate that we will be able to fully fund our projected CAPEX in 2013 from operating cash flow and cash on hand.

SARATOGA RESOURCES, INC.

During the year, we drilled and successfully completed 3 development wells and had a 4th development well drilled and tested and awaiting completion at year end for a total capital expenditure of $39.6 million. We also successfully completed 11 out of 12 recompletions during 2012 for a total cost of $16.6 million and completed 16 successful workovers at a cost of $3.8 million.

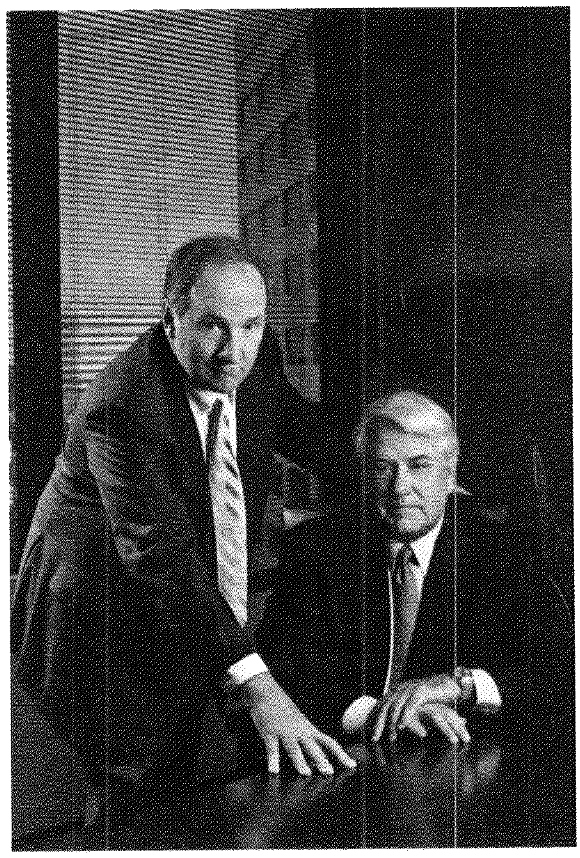
Although 2012 presented challenges, including facing the effects of Hurricane Isaac, we remain excited about our holdings and what we continue to view as the substantial untapped potential of those holdings, including opportunities to develop our deep inventory of conventional well prospects, potential exploitation of ultra-deep prospects and the prospects that we hope to gain once our shallow GOM shelf bids are finalized.

While natural gas reserves decreased, we booked net additions to oil reserves and are optimistic about the potential to more than replace 2012 reductions through reserve additions associated with the Gulf of Mexico leases on which we were apparent high bidder. As mentioned, we believe our stock is vastly undervalued on an NAV basis with $9.00 per share of NAV and we are trading at a sharp discount compared to our peers.

We believe that our stock has been subject to the more than 50% slide in share values in the Micro Cap E&P sector in the last 12 months and that, at present levels, our stock price fails to reflect the true value of our company, representing what we view as an even greater buying opportunity than ever before.

We thank you for your continued trust and commitment to our company and look forward to delivering on the promise of our assets in 2013 and the years to come.

Thomas F. Cooke	Andrew C. Clifford
Chairman/CEO	President



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