SARATOGA RESOURCES INC /TX
Form S-4/A
April 25, 2014

As filed with the Securities and Exchange Commission on April __, 2014

Registration No. 333-193337

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

Form S-4

REGISTRATION STATEMENT

UNDER THE SECURITIES ACT OF 1933

SARATOGA RESOURCES, INC.

(exact name of registrant as specified in its charter)

Texas	**1311**	**76-0314489**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

3 Riverway, Suite 1810
Houston, Texas 77056
(713) 458-1560
(Address, Including Zip Code, and Telephone Number,
Including Area Code, of Registrant s Principal Executive Offices)

Thomas Cooke
3 Riverway, Suite 1810
Houston, Texas 77056
(713) 458-1560

(Name, Address, Including Zip Code, and Telephone Number,
Including Area Code, of Agent for Service)

Copies to:

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Birmingham, Alabama 35203

(205) 250-5000

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Michael W. Sanders, Attorney at Law

138 Sailfish

Lakeway, Texas 78734

(281) 758-4136

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this Registration Statement.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration number of the earlier effective registration statement for the same offering. o

If this Form is a post effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

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

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction.

Exchange Act Rule 13e-4(i) (Cross-Border Issuer Tender Offer)	o
Exchange Act Rule 13d-1(d) (Cross-Border Third-Party Issuer Tender Offer)	o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered[(1)]	**Amount to be Registered**	**Proposed Maximum Offering Price per Note**[(1)]	**Proposed Maximum Aggregate Offering Price**[(1)]	**Amount of Registration Fee**[(3)(4)]
10.0% Senior Secured Notes due 2015	$ 54,600,000	100%	$ 54,600,000	$ 7,032.48
Guarantees[(2)]	N/A	N/A	N/A	
Total	$ 54,600,000		$ 54,600,000	$ 7,032.48

(1)

Estimated solely for the purpose of calculating the registration fee in accordance with Rule 457(f) under the Securities Act of 1933.

(2)

No separate consideration will be received for the guarantees, and no separate fee is payable pursuant to Rule 457(a) under the Securities Act of 1933.

(3)

In accordance with Rule 457(n) under the Securities Act of 1933, no separate fee is payable with respect to guarantees of the securities being registered.

(4)

Previously paid

Each Registrant hereby amends this Registration Statement on such dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

TABLE OF ADDITIONAL REGISTRANT GUARANTORS

Exact Name of Registrant Guarantors (1)	**State or Other**	**Primary**	**IRS**

	Jurisdiction of Incorporation or Formation	Standard Industrial Classification Code Number	Employer Identification Number
Harvest Oil & Gas, LLC	Louisiana	1311	20-1430003
The Harvest Group LLC	Louisiana	1311	20-1233158
Lobo Resources, Inc.	Texas	1311	74-2697201
Lobo Operating, Inc.	Texas	1311	76-0436990

(1)

The address for each of the Guarantors is 3 Riverway, Suite 1810, Houston, Texas 77056 and the telephone number for the Registrant Guarantors (713) 458-1560.

The information in this preliminary prospectus is not complete and may be changed without notice. This preliminary prospectus is not an offer to sell nor does it seek an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated April 24, 2014

PROSPECTUS

Saratoga Resources, Inc.

Offer to Exchange

$54,600,000 of 10.0% Senior Secured Notes due 2015

that have been registered under the Securities Act of 1933

for

$54,600,000 of 10.0% Senior Secured Notes due 2015

that have not been registered under the Securities Act of 1933

Saratoga Resources, Inc. is offering to exchange registered 10.0% Senior Secured Notes due 2015, or the exchange notes, for any and all of its unregistered 10.0% Senior Secured Notes due 2015, or the outstanding notes, that were issued pursuant to a private placement on November 22, 2013. We refer to the outstanding notes and the exchange notes together in this prospectus as the notes. We refer to this exchange as the exchange offer. The exchange notes are substantially identical to the outstanding notes, except the exchange notes are registered under the Securities Act of 1933, as amended (the Securities Act), and the transfer restrictions and registration rights, and related additional interest provisions, applicable to the outstanding notes will not apply to the exchange notes. The exchange notes will represent the same debt as the outstanding notes and we will issue the exchange notes under the same indenture used in issuing the outstanding notes.

Terms of the exchange offer:

The exchange offer expires at 5:00 p.m., New York City time, on , 2014, unless we extend it.

The exchange offer is subject to customary conditions, which we may waive.

We will exchange all outstanding notes that are validly tendered and not withdrawn prior to the expiration of the exchange offer for an equal principal amount of exchange notes. All interest due and payable on the outstanding notes will become due and payable on the same terms under the exchange notes.

You may withdraw your tender of outstanding notes at any time prior to the expiration of the exchange offer.

If you fail to tender your outstanding notes, you will continue to hold unregistered, restricted securities, and your ability to transfer them could be adversely affected.

We believe that the exchange of exchange notes for outstanding notes will not be a taxable transaction for U.S. federal income tax purposes, but you should see the discussion under the caption Material U.S. Federal Income and Estate Tax Considerations for more information.

We will not receive any proceeds from the exchange offer.

Please read Risk Factors beginning on page 7 for a discussion of factors you should consider before deciding whether to participate in the exchange offer.

Each broker-dealer that receives the exchange notes for its own account pursuant to this exchange offer must acknowledge by way of the letter of transmittal that it will deliver a prospectus in connection with any resale of the exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, such broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the exchange notes received in exchange for outstanding notes where such outstanding notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Until , 2014 all dealers that effect transactions in the exchange notes, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters with respect to their unsold allotments or subscriptions. We have agreed that, until , 2014, we will make this prospectus available to any broker-dealer for use in connection with any such resale. See Plan of Distribution.

Neither the Securities and Exchange Commission (the SEC) nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

YOU SHOULD READ THIS ENTIRE DOCUMENT AND THE ACCOMPANYING LETTER OF TRANSMITTAL AND RELATED DOCUMENTS AND ANY AMENDMENTS OR SUPPLEMENTS CAREFULLY BEFORE MAKING YOUR DECISION TO PARTICIPATE IN THE EXCHANGE OFFER.

The date of this prospectus is , 2014.

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This prospectus is part of a registration statement we filed with the SEC. In making your decision whether to participate in this exchange offer, you should rely only on the information contained in or incorporated by reference into this prospectus and in the letter of transmittal accompanying this prospectus. We have not authorized any other person to provide you with additional or different information. If you receive any unauthorized information, you must not rely on it. We are not making an offer to sell these securities in any jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus or in the documents incorporated by reference into this prospectus is accurate as of any date other than the date on the front cover of this prospectus or the date of such incorporated documents, as the case may be.

This prospectus incorporates by reference business and financial information about us that is not included in or delivered with this prospectus. This information is available without charge upon written or oral request directed to: Saratoga Resources, Inc., Attention: Investor Relations, 3 Riverway, Suite 1810, Houston, Texas 77056; telephone number: (713) 458-1560.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain oil and natural gas terms used in this prospectus:

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 offering circular in reference to oil and other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

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

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

Boepd Boe per day.

Bopd Bbls of oil (or condensate) per day.

Btu One British thermal unit.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MBbl One thousand barrels of oil or other liquid hydrocarbons.

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

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

Mcf One thousand cubic feet of natural gas.

Mcfpd Mcf per day.

MMBbl One million barrels of oil or other liquid hydrocarbons.

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

MMBtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

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

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

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

NGLs Natural gas liquids.

NYMEX The New York Mercantile Exchange.

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

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

PDP Proved developed producing.

PDNP Proved developed nonproducing.

plugback To shut off lower formation in a well bore.

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

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

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

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

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

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

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

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

proved reserves Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under current economic conditions, operating methods and government regulations. Proved reserves can be categorized as developed or undeveloped. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

proved undeveloped reserves (PUD) Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SUMMARY

This summary highlights selected information about us, but does not contain all the information that may be important to you. This prospectus includes specific information about the exchange offer and our business. You should read this prospectus carefully, including the matters set forth under the caption Risk Factors before making a decision whether to participate in the exchange offer.

In this prospectus, except under the caption Description of the Exchange Notes and unless the context indicates otherwise, references to Saratoga, the Company, we , our and us refer to Saratoga Resources, Inc. and its subsid

Our Company

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, 2013, our properties consisted of 52,103 acres under lease, including 32,289 acres gross/net located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana and 19,814 acres gross/net under federal leases in the shallow Gulf of Mexico shelf.

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

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

As of December 31, 2013, our total proved reserves were 17.2 MMBoe, consisting of 9.2 MMBbls of oil and 48.0 Bcf of natural gas, approximately 84% of which was attributable to state and parish properties. The PV-10 of our proved reserves at December 31, 2013 was $410.8 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $357.7 million. Additionally, we had probable reserves of 16.8 MMBoe, consisting of 6.9 MMBbls of oil and 59.5 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities. We operate over 95% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

Corporate Information

Our principal executive offices are located at 3 Riverway, Suite 1810, Houston, Texas 77056. We can be reached at (713) 458-1560, and our website address is *www.saratogaresources.com*. Information on our website is not part of this prospectus.

The Exchange Offer

On November 22, 2013, we completed a private offering of $54.6 million aggregate principal amount of the outstanding notes for cash in the amount of $27.3 million and surrender for cancellation of $27.3 million in face amount of 12½% senior secured notes due 2016. As part of this private offering, we entered into a registration rights agreement with the purchasers of the outstanding notes in which we agreed, among other things, to use our commercially reasonable efforts to complete the exchange offer no later than approximately 165 days after November 22, 2013. The following is a summary of the exchange offer.

Outstanding Notes	On November 22, 2013, we issued $54.6 million aggregate principal amount of 10.0% Senior Secured Notes due 2015. The outstanding notes were issued for a combination of cash in the amount of $27.3 million and surrender for cancellation of $27.3 million in face amount of 12½% senior secured notes due 2016.
Exchange Notes	10.0% Senior Secured Notes due 2015. The terms of the exchange notes are identical to the terms of the outstanding notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding notes will not apply to the exchange notes.
Exchange Offer	We are offering to exchange up to $54.6 million principal amount of our 10.0% Senior Secured Notes due 2015 that have been registered under the Securities Act of 1933, or the Securities Act, for an equal amount of our outstanding 10.0% Senior Secured Notes due 2015 issued on November 22, 2013 to satisfy our obligations under the registration rights agreement that we entered into when we issued the outstanding notes in a transaction exempt from registration under the Securities Act.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on , 2014, unless we extend it.
Conditions to the Exchange Offer	The registration rights agreement does not require us to accept outstanding notes for exchange if the exchange offer or the making of any exchange by a holder of the outstanding notes would violate any applicable law or SEC policy. There is no condition to the exchange offer that a minimum aggregate principal amount of outstanding notes be tendered. Please read The Exchange Offer Conditions to the Exchange Offer for more information about the conditions to the exchange offer.
Procedures for Tendering Outstanding Notes	To participate in this exchange offer, you must complete, sign and date the letter of transmittal or its facsimile and transmit it, together with your outstanding notes to be exchanged and all other documents required by the letter of transmittal, to The Bank of New York Mellon Trust Company, N.A., as exchange agent, at its address indicated herein. In the

	alternative, you can tender your original notes by book-entry delivery following the procedures described in this prospectus.
	For more details, please read The Exchange Offer Terms of the Exchange Offer and The Exchange Offer Procedures for Tendering.
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	You may withdraw your tender of outstanding notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent before 5:00 p.m., New York City time, on the expiration date of the exchange offer. Please read The Exchange Offer Withdrawal of Tenders.

Acceptance of Outstanding Notes and Delivery of Exchange Notes	If you fulfill all conditions required for proper acceptance of outstanding notes, we will accept any and all outstanding notes that you properly tender in the exchange offer before 5:00 p.m., New York City time, on the expiration date. We will return to you any outstanding note that we do not accept for exchange without expense promptly after the expiration date. We will deliver the exchange notes promptly after the expiration date. Please read The Exchange Offer Terms of the Exchange Offer.
Use of Proceeds	We will not receive any proceeds from the issuance of the exchange notes. We are making the exchange offer solely to satisfy our obligations under the registration rights agreement.
Consequences of Failure to Exchange Outstanding Notes	If you do not exchange your outstanding notes in the exchange offer, you will no longer be able to require us to register the outstanding notes under the Securities Act, except in the limited circumstances provided under our registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the outstanding notes unless we have registered the outstanding notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.
Material U.S. Federal Income Tax Considerations	We believe that the exchange of exchange notes for outstanding notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read Material U.S. Federal Income and Estate Tax Considerations.
Exchange Agent	We have appointed The Bank of New York Mellon Trust Company, N.A. as the exchange agent for the exchange offer. You should direct questions and requests for assistance and requests for additional copies of this prospectus (including the letter of transmittal) to the exchange agent addressed as follows:

The Bank of New York Mellon Trust Company, N.A. as Exchange Agent
c/o The Bank of New York Mellon Corporation
Corporate Trust Operations Reorganization Unit
111 Sanders Creek Parkway
East Syracuse, NY 13057
Attention: Dacia Brown-Jones
Telephone: (315) 414-3349
Facsimile: (732) 667-9408

Terms of the Exchange Notes

The exchange notes will be identical to the outstanding notes, except that the exchange notes will be registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The exchange notes will evidence the same debt as the outstanding notes, and the same indenture will govern the exchange notes and the outstanding notes. We refer to both the exchange notes, the outstanding notes, and the original issuance notes together as the notes.

The following summary contains basic information about the exchange notes and is not intended to be complete. It does not contain all the information that may be important to you. For a more complete understanding of the exchange notes, please read Description of the Exchange Notes.

Issuer	Saratoga Resources, Inc.
Notes Offered	$54,600,000 aggregate principal amount of 10.0% senior secured notes due 2015.
Maturity Date	December 31, 2015.
Interest Rate	The exchange notes will bear interest at a rate of 10.0% per year.
Interest Payment Dates	March 31, June 30, September 30 and December 31 of each year to holders of record as of the preceding March 15, June 15, September 15 and December 15, respectively. The initial interest payment on the exchange notes will include all accrued and unpaid interest on the outstanding notes exchanged therefor. See Description of the Exchange Notes Principal, Maturity and Interest.
Guarantees	The exchange notes will be fully and unconditionally guaranteed, jointly and severally, on a senior secured basis by each of our existing and future domestic subsidiaries, which we refer to in this prospectus as the guarantors.
Security Interest	The notes and the guarantees will be secured by liens on substantially all of our and the guarantors assets, subject to certain exceptions and permitted liens. Pursuant to the terms of an intercreditor agreement, discussed below, the notes rank senior in right, priority, operation, effect and all other respects to any liens with respect to collateral securing the obligations under the indenture (the Second Lien Indenture) relating to $125.2 million in face amount of 12½% senior secured notes due 2016 (the Second Lien Notes).

Under the terms of the indenture governing the notes (the First Lien Indenture), additional notes issued under the First Lien Indenture and secured by collateral on a pari passu or senior basis with the lien on the collateral securing the notes may not exceed $10.0 million without the prior consent of holders of at least 75% in aggregate principal amount of the notes outstanding. See Description of the Exchange Notes Security.

Intercreditor Agreement	Pursuant to the terms of an intercreditor agreement entered into with The Bank of New York Mellon Trust Company, N.A., in its capacity as trustee and collateral agent under the First Lien Indenture (the First Lien Agent), and The Bank of New York Mellon Trust Company, N.A., in its capacity as trustee and collateral agent (the Second Lien Agent) under the Second Lien Indenture, the holders of the notes and any other pari passu indebtedness will receive proceeds from the collateral prior to the holders of Second Lien Notes. In addition to defining the relative priorities of the respective security interests in the assets securing the notes, the intercreditor agreement sets forth certain matters relating to administration of security interests, exercise of remedies, certain bankruptcy-related provisions and other intercreditor matters. See Description of the Exchange Notes Intercreditor Agreement.

Ranking	The exchange notes will be our and the guarantors senior secured obligations. The exchange notes will: rank equal in right of payment with all of our and the guarantors existing and future senior indebtedness; rank senior in right of payment to all of our and the guarantors existing and future subordinated indebtedness; be effectively senior to all of our and the guarantors existing and future unsecured indebtedness to the extent of the value of the collateral securing such indebtedness; be effectively senior to our and the guarantors obligations under the Second Lien Indenture; and be structurally junior to all existing and future indebtedness and other liabilities of each of our non-guarantor subsidiaries, if any.
Redemption of the Notes at Our Option	We may redeem some or all of the notes, at our sole option and at any time, at 100% of the principal amount to be redeemed plus accrued and unpaid interest, if any, to the date of redemption. See Description of the Exchange Notes Optional Redemption.
Change of Control	If we experience certain kinds of changes of control (as defined in the indenture governing the notes), the holders of the notes will have the right to require us to purchase all or a portion of their notes at an offer price in cash equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase. See Description of the Exchange Notes Repurchase at the Option of Holders Change of Control.
Asset Sale	Upon certain asset sales, we may be required to offer to use the net proceeds of an asset sale to purchase the notes at 100% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase. See Description of the Exchange Notes Repurchase at the Option of Holders Asset Sale.

Certain Covenants	The indenture governing the exchange notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to:

- transfer or sell assets or use asset sale proceeds;
- pay dividends or make distributions, redeem subordinated debt or make other restricted payments;
- make certain investments;
- incur or guarantee additional debt or issue preferred equity securities;
- issue or sell capital stock of certain subsidiaries;
- create or incur certain liens on our assets;
- incur dividend or other payment restrictions affecting our restricted subsidiaries;
- merge, consolidate or transfer all or substantially all of our assets;

	enter into certain transactions with affiliates;
	engage in a business other than a business that is the same or similar to our current business and reasonably related businesses; and
	take or omit to take any actions that would adversely affect or impair in any material respect the collateral securing the notes.
	These covenants are subject to a number of important exceptions and limitations and are described in more detail under Description of the Exchange Notes Certain Covenants.
Absence of a Public Market for the Notes	The exchange notes generally will be freely transferable, but will also be new securities for which there is currently no established market. We do not intend to make a trading market in the exchange notes after the exchange offer. Accordingly, a market for the exchange notes may not develop, or if one does develop, it may not provide adequate liquidity.
Global Notes	The exchange notes will be evidenced by one or more global notes deposited with the trustee as custodian for DTC. These global notes will be registered in the name of Cede & Co., as DTC s nominee.
Risk Factors	You should consider carefully all of the information set forth in this prospectus and incorporated by reference and, in particular, you should evaluate the risks described under Risk Factors in this prospectus and in our filings with the SEC before making a decision whether to participate in the exchange offer.
No Listing of the Notes	We do not intend to apply to list the notes on any securities exchange.
Trustee and Exchange Agent	The Bank of New York Mellon Trust Company, N.A.

RISK FACTORS

You should consider carefully the risks discussed below before making a decision whether to participate in the exchange offer. Additional risks and uncertainties described elsewhere in this prospectus may also adversely affect our business, operating results, financial condition and prospects, as well as the value of the exchange notes.

If any of the following risks actually were to occur, our business, financial condition, results of operations or cash flow could be affected materially and adversely. In that case, you could lose all or part of your investment in or fail to achieve the expected return on the notes.

Risks Related to the Exchange Offer

If you fail to exchange outstanding notes, existing transfer restrictions will remain in effect and the market value of outstanding notes may be adversely affected because they may be more difficult to sell.

If you fail to exchange outstanding notes for exchange notes under the exchange offer, you will continue to be subject to the existing transfer restrictions on your outstanding notes. In general, the outstanding notes may not be offered or sold unless they are registered or exempt from registration under the Securities Act and applicable state securities laws. Except in connection with this exchange offer or as required by the registration rights agreement, we do not intend to register resales of the outstanding notes.

Any tenders of outstanding notes under the exchange offer will reduce the principal amount of the currently outstanding notes. Due to the corresponding reduction in liquidity, this may have an adverse effect upon, and increase the volatility of, the market price of any currently outstanding notes that you continue to hold following completion of the exchange offer.

Risks Related to the Notes

Forward-looking production estimates presented in this prospectus will differ from our actual results.

Forward-looking production estimates we have included, or that may be incorporated by reference, in this prospectus are based upon a number of assumptions and on information that we believe are reliable as of today. However, these forward-looking production estimates and assumptions are inherently subject to significant business and economic uncertainties, many of which are beyond our control. These forward-looking production estimates are necessarily speculative in nature, and you should expect that some or all of the assumptions will not materialize. Actual results will vary from the forward-looking production estimates and the variations will likely be material and are likely to increase over time. Consequently, the inclusion of these forward-looking production estimates in this prospectus should not be regarded as a representation by us or any other person that the forward-looking production estimates will actually be achieved. Moreover, we do not intend to update or otherwise revise these forward-looking production estimates to reflect events or circumstances after the date of this prospectus to reflect the occurrence of unanticipated events. You are cautioned not to place undue reliance on the forward-looking production estimates.

Our forward-looking production estimates were not prepared with a view toward compliance with published guidelines of the SEC, the American Institute of Certified Public Accountants, the Society of Petroleum Engineers, the World Petroleum Congress or any other regulatory or professional body or generally accepted accounting principles. No independent accountants or independent petroleum engineers compiled or examined the forward-looking production estimates, and accordingly no independent accountant or independent petroleum engineer has expressed an opinion or any other form of assurances with respect thereto or has assumed any responsibility for the forward-looking production estimates. Further, our independent petroleum engineers made different assumptions when calculating our respective proved reserve estimates. As a result, our forward-looking production estimates may not accurately portray our proved reserves in the future.

Our leverage and debt service obligations may adversely affect our cash flow and our ability to make payments on the notes.

We have a substantial amount of debt currently outstanding. As of December 31, 2013, we would have had approximately $179.8 million of debt outstanding.

Our substantial level of indebtedness could have important consequences to you, including the following:

it may make it difficult for us to satisfy our obligations under the notes, our other indebtedness and contractual and commercial commitments;

we must use a substantial portion of our cash flow from operations to pay interest on the notes and our other indebtedness, which will reduce the funds available to us for other purposes;

our ability to obtain additional debt financing in the future for working capital, capital expenditures, acquisitions or general corporate purposes may be limited;

our flexibility in reacting to changes in the industry may be limited and we could be more vulnerable to adverse changes in our business or economic conditions in general; and

we may be at a competitive disadvantage to those of our competitors who operate on a less leveraged basis.

Despite current indebtedness levels, we may still be able to incur more debt, which would increase the risks associated with our substantial leverage.

Even with our existing debt levels, we and our subsidiaries may be able to incur additional indebtedness in the future. Although the indenture governing the notes includes restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions and, under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If we incur additional indebtedness, the related risks that we now face would intensify and could further exacerbate the risks associated with our substantial leverage.

We may not be able to generate sufficient cash flow to meet our debt service and other obligations, including the notes, due to events beyond our control.

Our ability to generate cash flows from operations and to make scheduled payments on or refinance our indebtedness, including the notes, and to fund working capital needs and planned capital expenditures will depend on our future financial performance and our ability to generate cash in the future. Our future financial performance will be affected by a range of economic, financial, competitive, business and other factors that we cannot control, such as general economic and financial conditions in the oil and gas industry, the economy generally or other risks summarized here. A significant reduction in operating cash flows resulting from adverse changes in the oil and gas industry or general economic conditions, increased competition or other events beyond our control could increase the need for additional or alternative sources of liquidity and could have a material adverse effect on our business, financial condition, results of operations, prospects and our ability to service our debt and other obligations, including the notes. If we are unable to service our indebtedness or to fund our other liquidity needs, we may be forced to adopt an alternative strategy that may include actions such as reducing or delaying capital expenditures, selling assets, restructuring or refinancing our indebtedness, seeking additional capital, or any combination of the foregoing. If we raise additional debt, it would increase our interest expense, leverage and our operating and financial costs. We cannot assure you that any of these alternative strategies could be effected on satisfactory terms, if at all, or that they would yield sufficient funds to make required payments on the notes and any other indebtedness or to fund our other liquidity needs. Reducing or delaying capital expenditures or selling assets could delay or reduce future cash flows. In addition, the terms of existing or future debt agreements, including the indenture governing the notes, may restrict us from adopting any of these alternatives. We cannot assure you that our business will generate sufficient cash flows from operations or that future borrowings will be available in an amount sufficient to enable us to pay our indebtedness, including these notes, or to fund our other liquidity needs.

The failure to generate sufficient cash flows or to effect any of these alternatives could significantly adversely affect the value of the notes and our ability to pay amounts due under the notes. If for any reason we are unable to meet our debt service and repayment obligations, including under the notes, we would be in default under the terms of the agreements governing our indebtedness, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable. This would likely in turn trigger cross-acceleration or cross-default rights between our applicable debt agreements. Under these circumstances, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on the notes. In addition, these lenders could then seek to foreclose on our assets that are their collateral. If the amounts outstanding under our indebtedness, including under the notes, were to be accelerated, or were the subject of foreclosure actions, we cannot assure you that our assets would be sufficient to repay in full the money owed to our debt holders, including you as a noteholder.

In particular, we note that we have periodically experienced declines in revenues and profitability associated with curtailment or shut-in of production due to tropical storms and hurricanes and decreases in commodity prices. Declines in revenues and profitability arising from such events may result in reduced cash flows and deferral of planned development activities which may, in turn, result in a delay in the commencement of anticipated revenues from delayed projects. Any such developments in the future could adversely affect our ability to service our debt.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the limited liability company interests and other equity interests in our subsidiaries. As a result, our ability to make required payments on the notes will depend on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, applicable state laws and other laws and regulations. If we are unable to obtain the funds necessary to pay the principal amount of the notes, or to repurchase the notes upon the occurrence of a change of control, or if our subsidiaries are unable to satisfy their obligations as guarantors of the notes, we may be required to adopt one or more alternatives, such as a refinancing of the notes. We cannot assure you that we would be able to refinance the notes.

The indenture governing the notes imposes significant operating and financial restrictions which may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

The indenture governing the notes contains customary restrictions on our activities, including covenants that limit our and our restricted subsidiaries ability to:

- transfer or sell assets or use asset sale proceeds;
- incur or guarantee additional indebtedness or issue preferred equity securities;
- pay dividends, redeem subordinated indebtedness or make other restricted payments;
- make certain investments;
- create or incur certain liens on our assets;
- incur dividend or other payment restrictions affecting our restricted subsidiaries;
- enter into certain transactions with affiliates;
- merge, consolidate or transfer all or substantially all of our assets;
- engage in a business other than a business that is the same or similar to our current business and reasonably related businesses; and
- take or omit to take any actions that would adversely affect or impair in any material respect the collateral securing the notes.

The restrictions in the indenture governing the notes may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We also may incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all. The breach of any of these covenants and restrictions could result in a default under the indenture governing the notes. An event of default under any agreement governing our indebtedness could permit some of our lenders to declare all amounts borrowed from them to be due and payable.

Our ability to repurchase the notes with cash upon a change of control or upon an offer to repurchase the notes in the case of an asset sale, as required by the indenture, may be limited.

Upon the occurrence of a change of control, as defined in the indenture governing the notes, we will be required to offer to repurchase all of the outstanding notes at 101% of the aggregate principal amount of the notes repurchased, plus accrued and unpaid interest to the date of repurchase. See Description of the Exchange Notes Repurchase at the Option of Holders Change of Control. In addition, upon the occurrence of certain asset sales, as defined in the indenture governing the notes, we will be required to offer to repurchase all of the outstanding notes at 100% of the aggregate principal amount of the notes repurchased, plus accrued and unpaid interest to the date of repurchase. See Description of the Exchange Notes Repurchase at the Option of Holders Asset Sales.

However, it is possible that we will not have sufficient funds at the time of the change of control or upon an asset sale to make the required repurchase of notes. Our failure to purchase tendered notes would constitute an event of default under the indenture governing the notes, which, in turn, would likely constitute a default under the agreements governing any other indebtedness we may have in place. In that event, we may be required to cure or refinance our other indebtedness, if any, before making an offer to purchase.

Moreover, the agreements governing any future indebtedness we incur may restrict our ability to repurchase the notes, including following a change of control event or upon an asset sale, as required by the indenture. As a result, following such an event, we would not be able to repurchase notes unless we first repay all such indebtedness or obtain a waiver from the holders of such indebtedness to permit us to repurchase the notes. We may be unable to repay all of that indebtedness or obtain a waiver of that type. Any requirement to offer to repurchase outstanding notes may therefore require us to refinance any other outstanding debt, which we may not be able to do on commercially reasonable terms, if at all. These repurchase requirements may also delay or make it more difficult for others to obtain control of us.

In addition, certain important corporate events, such as takeovers, recapitalizations, restructurings, mergers or similar transactions, may not constitute a change of control under the indenture governing the notes and, therefore, would not permit the holders of the notes to require us to repurchase the notes. See Description of the Exchange Notes Repurchase at the Option of Holders Change of Control.

In addition, the definition of change of control includes a phrase relating to the sale or other transfer of all or substantially all of the properties or assets of the company and its subsidiaries, taken as a whole. There is no precise definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty in ascertaining whether a particular transaction would involve a disposition of all or substantially all of the assets of the company, and, therefore, it may be unclear as to whether a change of control has occurred and whether the holders of the notes have the right to require us to repurchase such notes.

The notes are secured only to the extent of the value of the assets that have been granted as security for the notes and in the event that the security is enforced against the collateral, the holders of the notes will receive proceeds from the collateral only after certain other permitted indebtedness have been paid in full.

If we default on the notes, the holders of the notes will be secured only to the extent of the value of the assets underlying their security interest. Furthermore, upon enforcement against any collateral or insolvency, proceeds of such enforcement will first be used to pay certain other permitted indebtedness prior to paying the notes. See *The rights of holders of notes in the collateral may be adversely affected by the intercreditor agreement.*

The value of the noteholders security interest in the collateral may not be sufficient to satisfy all our obligations under the notes.

The notes and the guarantees of the notes are secured on a senior secured basis by a lien on the assets that secure our obligations under our existing Second Lien Notes, including accounts, chattel paper, instruments, letter of credit rights, documents, equipment, general intangibles, inventory, cash and deposit accounts, investment property, owned real property and proceeds of the foregoing, in each case, subject to certain permitted liens and certain excluded assets. See Description of the Exchange Notes Security.

If we default on the notes, the holders of the notes will be secured only to the extent of the value of the assets underlying their security interest. Furthermore, upon enforcement against any collateral or insolvency, under the terms of our intercreditor agreement, proceeds of such enforcement will be used first to pay certain other permitted indebtedness and then to pay the notes. To prevent foreclosure, we may be motivated to commence voluntary bankruptcy proceedings, or the holders of the notes and/or various other interested persons may be motivated to institute bankruptcy proceedings against us. The commencement of such bankruptcy proceedings would expose the holders of the notes to additional risks, including additional restrictions on exercising rights against collateral. See *Rights of holders of notes in the collateral may be adversely affected by bankruptcy proceedings*.

The indenture governing the notes will allow us to incur additional obligations secured by liens in amounts that may be significant. Any additional indebtedness or obligations secured by a lien on the collateral securing the notes could adversely affect the relative position of the holders of the notes with respect to the collateral securing the notes.

The collateral may be subject to exceptions, defects, encumbrances, liens and other imperfections. Further, the value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. By its nature, some or all of the collateral may be illiquid and may have no readily ascertainable market value. The value of the assets pledged as collateral for the notes could be impaired in the future as a result of changing trends in the energy markets, economic conditions, our failure to implement our business strategy, competition or other future trends. In the event of a foreclosure, liquidation, bankruptcy or similar proceeding, no assurance can be given that the proceeds from any sale or liquidation of the collateral will be sufficient to pay our obligations under the notes, in full or at all, after first satisfying our obligations under certain other permitted indebtedness. There also can be no assurance that the collateral will be saleable, and, even if saleable, the timing of its liquidation would be uncertain.

In addition, we may not have liens perfected on all of the collateral securing the notes or, in some cases, such liens may not be perfected at all. To the extent certain security interests have not been previously granted, filed and/or perfected, a covenant in the indenture governing the notes requires us to do or cause to be done all things that may be required under applicable law, or that the trustee under the indenture governing the notes from time to time may reasonably request, to grant, preserve, protect and perfect the validity and priority of the security interest in the collateral. We cannot assure you that we will be able to perfect the security interests on a timely basis, and our failure to do so may result in a default under the indenture.

Accordingly, there may not be sufficient collateral to pay all or any of the amounts due on the notes. Any claim for the difference between the amount, if any, realized by holders of the notes from the sale of the collateral securing the notes and the obligations under the notes will rank equally in right of payment with all of our other unsecured unsubordinated indebtedness and other obligations, including trade payables.

With respect to some of the collateral, the trustee s security interest and ability to foreclose will also be limited by the need to meet certain requirements, such as obtaining third-party consents and making additional filings. If we are unable to obtain these consents or make these filings, the security interests may be invalid and the holders will not be entitled to the collateral or any recovery with respect thereto. We cannot assure you that any such required consents can be obtained on a timely basis or at all. These requirements may limit the number of potential bidders for certain collateral in any foreclosure and may delay any sale, either of which events may have an adverse effect on the sale price of the collateral. Therefore, the practical value of realizing on the collateral may, without the appropriate consents and filings, be limited.

The collateral is subject to casualty risks.

We will be obligated under the indenture and collateral arrangements governing the notes to maintain adequate insurance or otherwise insure against hazards as is typically done by corporations having assets of a similar nature in the same or similar localities. There are, however, certain losses that may be either uninsurable or not economically insurable, in whole or in part. As a result, it is possible that the insurance proceeds will not compensate us fully for our losses. If there is a total or partial loss of any of the pledged collateral, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all of our secured obligations, including the notes.

The security interest in after-acquired property may not be perfected promptly or at all.

Applicable law requires that security interests in certain property acquired after the grant of a general security interest can only be perfected at the time such property and rights are acquired and identified. There can be no assurance that the trustee or the collateral agent will monitor, or that we will inform such trustee or collateral agent of, the future acquisition of property and rights that constitute collateral, and that the necessary action will be taken to properly perfect the security interest in such after-acquired collateral. Neither the trustee nor the collateral agent has an obligation to monitor the acquisition of additional property or rights that constitute collateral or the perfection of any security interest. Such failure may result in the loss of the security interest in certain of the after-acquired collateral or the priority of the security interest in favor of the notes against third parties.

There are circumstances other than repayment or discharge of the notes under which the collateral securing the notes and guarantees will be released automatically, without holders consent or the consent of the trustee under the indenture governing the notes.

Under various circumstances, all or a portion of the collateral securing the notes and the guarantees may be released automatically, including:

- a sale, transfer or other disposal of such collateral in a transaction not prohibited under the indenture governing the notes, including the sale of any entity in its entirety that owns or holds such collateral;

to the extent required in accordance with the intercreditor agreement;

to the extent we have defeased or satisfied and discharged the indenture governing the notes; and

with respect to collateral held by a guarantor, upon the release of such guarantor from its guarantee.

In addition, a guarantee will be automatically released in connection with a sale of such guarantor in a transaction not prohibited under the indenture governing the notes.

Certain assets will be excluded from the collateral.

Certain assets are excluded from the collateral securing the notes, as described in Description of the Exchange Notes Security, including the following:

any capital stock of any foreign subsidiaries of the guarantors in excess of 65% of the capital stock of such foreign subsidiaries;

items as to which a security interest cannot be granted without violating contract rights or applicable law;

assets securing purchase money debt or capitalized lease obligations permitted to be incurred under the indenture to the extent the documentation relating to such purchase money debt or capitalized lease obligations prohibits such assets from being collateral; and

certain other exceptions described in the security documents governing the notes.

If an event of default occurs and the notes are accelerated, the notes will rank equally with the holders of all of our other unsubordinated and unsecured indebtedness and other liabilities with respect to such excluded assets. As a result, if the value of the security interest for the notes and the guarantees is less than the value of the claims of the holders of the notes, no assurance can be provided that the holders of the notes would receive any substantial recovery from the excluded assets.

The rights of holders of notes in the collateral may be adversely affected by the intercreditor agreement.

Under the terms of the intercreditor agreement, the liens securing the obligations under certain permitted indebtedness will be paid prior to the obligations under the notes and guarantees in the event of any foreclosure or bankruptcy event. Additionally, the intercreditor agreement generally permits each of the notes trustee and the collateral agent for the existing Second Lien Notes to independently enforce their liens on the collateral (provided that distributions received on enforcement are applied as provided in the intercreditor agreement). It is possible that disputes may occur between the holders of the notes and other secured parties as to the appropriate manner of pursuing enforcement remedies with respect to the collateral which may delay enforcement of the collateral, result in litigation and/or result in enforcement actions against the collateral that are not approved by the holders of the notes. See Description of the Exchange Notes Security and Description of the Exchange Notes Intercreditor Agreement.

Rights of holders of notes in the collateral may be adversely affected by bankruptcy proceedings.

The right of the collateral agent for the notes to repossess and dispose of the collateral securing the notes upon acceleration is likely to be significantly impaired by federal bankruptcy law if bankruptcy proceedings are commenced by or against us prior to or possibly even after the collateral agent has repossessed and disposed of the collateral. Under the U.S. Bankruptcy Code, a secured creditor, such as the collateral agent for the notes, is prohibited from repossessing its security from a debtor in a bankruptcy case, or from disposing of security repossessed from a debtor, without bankruptcy court approval. Moreover, bankruptcy law permits the debtor to continue to retain and to use collateral, and the proceeds, products, rents, or profits of the collateral, even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given adequate protection. The meaning of the term adequate protection may vary according to circumstances, but it is intended in general to protect the value of the secured creditor s interest in the collateral and may include cash payments or the granting of additional security, if and at such time as the court in its discretion determines, for any diminution in the value of the collateral as a result of the stay of repossession or disposition or any use of the collateral by the debtor during the pendency of the bankruptcy case. In view of the broad discretionary powers of a bankruptcy court, it is impossible to predict how long payments under the notes could be delayed following commencement of a bankruptcy case, whether or when the collateral agent would repossess or dispose of the collateral, or whether or to what extent holders of the notes would be compensated for any delay in payment of loss of value of the collateral through the requirements of adequate protection. Furthermore, in the event the bankruptcy court determines that the value of the collateral is not sufficient to repay all amounts due on the notes, the holders of the notes would have undersecured claims as to the difference. Federal bankruptcy laws do not permit the payment or accrual of interest, costs, and attorneys fees for undersecured claims during the debtor s bankruptcy case. Additionally, the trustee s ability to foreclose on the collateral on your behalf may be subject to the consent of third parties, prior liens and practical problems associated with the realization of the trustee s security interest in the collateral. Moreover, the debtor or trustee in a bankruptcy case may seek to avoid an alleged security interest in collateral for the benefit of the bankruptcy estate. It may successfully do so if the security interest is not properly perfected or was perfected within a specified period of time (generally 90 days) prior to the initiation of such proceeding. Under such circumstances, a creditor may hold no security interest and be treated as holding a general unsecured claim in the bankruptcy case. It is impossible to predict what recovery (if any) would be available for such an unsecured claim if we became a debtor in a bankruptcy case. While U.S. bankruptcy law generally invalidates provisions restricting a debtor s ability to assume and/or assign a contract, there are exceptions to this rule which could be applicable in the event that we become subject to a U.S. bankruptcy proceeding.

Any future pledge of collateral may be avoidable in bankruptcy.

Any future pledge of collateral in favor of the trustee or collateral agent for the notes, including pursuant to security documents delivered after the date of the indenture governing the notes, may be avoidable in bankruptcy if certain events or circumstances exist or occur, including, among others, if:

- the pledgor is insolvent at the time of the pledge, the pledge permits the holder of the notes to receive a greater recovery than if the pledge had not been given; and

- a bankruptcy proceeding in respect of the pledgor is commenced within 90 days following the pledge, or, in certain circumstances, a longer period.

Federal, state and foreign fraudulent transfer laws may permit a court to avoid the notes and the guarantees, subordinate claims in respect of the notes and the guarantees and require noteholders to return payments received. If this occurs, noteholders may not receive any payments on the notes.

Federal, state and foreign fraudulent transfer and conveyance statutes may apply to the issuance of the notes and the incurrence of any guarantees. Under federal bankruptcy law and comparable provisions of state fraudulent transfer or conveyance laws, which may vary from state to state and be different from other applicable foreign jurisdictions, the notes or guarantees could be avoided as a fraudulent transfer or conveyance if (1) we or any of the guarantors, as applicable, issued the notes or incurred the guarantees with the intent of hindering, delaying or defrauding creditors or (2) we or any of the guarantors, as applicable, received less than reasonably equivalent value or fair consideration in return for either issuing the notes or incurring the guarantees and, in the case of (2) only, one of the following is also true at the time thereof:

- we or any of the guarantors, as applicable, were insolvent or rendered insolvent by reason of the issuance of the notes or the incurrence of the guarantees;

- the issuance of the notes or the incurrence of the guarantees left us or any of the guarantors, as applicable, with an unreasonably small amount of capital to carry on the business;

- we or any of the guarantors intended to, or believed that we or such guarantor would, incur debts beyond our or such guarantor s ability to pay such debts as they mature; or

- we or any of the guarantors was a defendant in an action for money damages, or had a judgment for money damages docketed against us or such guarantor if, in either case, after final judgment, the judgment is unsatisfied.

A court would likely find that we or a guarantor did not receive reasonably equivalent value or fair consideration for the notes or such guarantee if we or such guarantor did not substantially benefit directly or indirectly from the issuance of the notes or the applicable guarantee. As a general matter, value is given for a transfer or an obligation if, in exchange for the transfer or obligation, property is transferred or an antecedent debt is secured or satisfied. A debtor will generally not be considered to have received value in connection with a debt offering if the debtor uses the proceeds of that offering to make a dividend payment or otherwise retire or redeem equity securities issued by the debtor.

We cannot be certain as to the standards a court would use to determine whether or not we or the guarantors were solvent at the relevant time or, regardless of the standard that a court uses, that the issuance of the guarantees would not be further subordinated to our other debt or the debt of the guarantors. Generally, however, an entity would be considered insolvent if, at the time it incurred indebtedness:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;

the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or

it could not pay its debts as they become due.

If a court were to find that the issuance of the notes or the incurrence of the guarantee was a fraudulent transfer or conveyance, the court could avoid the payment obligations under the notes or such guarantee or further subordinate the notes or such guarantee to our presently existing and future indebtedness or of the related guarantor, or require the holders of the notes to repay any amounts received with respect to such guarantee. In the event of a finding that a fraudulent transfer or conveyance occurred, noteholders may not receive any repayment on the notes. Further, the avoidance of the notes could result in an event of default with respect to our other debt that could result in acceleration of such debt.

Although each guarantee entered into by the guarantors contains a provision intended to limit that guarantor s liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent transfer, this provision may not be effective to protect those guarantees from being avoided under fraudulent transfer law, or may reduce that guarantor s obligation to an amount that effectively makes its guarantee worthless.

In addition, different or additional fraudulent conveyance laws may exist in foreign jurisdictions which could result in the liens being avoided.

If the guarantees by the subsidiary guarantors are not enforceable, the notes would be effectively subordinated to all liabilities of the subsidiary guarantors, including trade payables.

The value of the collateral securing the notes and the guarantees may not be sufficient to secure post-petition interest.

In the event of a bankruptcy, liquidation, dissolution, reorganization or similar proceeding against us, holders of the notes will only be entitled to post-petition interest under the U.S. Bankruptcy Code to the extent that the value of their security interest in the collateral securing the notes and the guarantees is greater than their pre-bankruptcy claim. Holders of the notes that have a security interest in collateral with a value equal or less than their prebankruptcy claim will not be entitled to post-petition interest under the U.S. Bankruptcy Code. No appraisal of the fair market value of the collateral has been prepared in connection with the exchange offer and therefore the value of the noteholders interest in the collateral may not equal or exceed the principal amount of the notes.

The notes could be wholly or partially voided as a preferential transfer.

If we or any guarantor become the subject of a bankruptcy proceeding within 90 days after the date of the indenture (or, with respect to any insiders specified in bankruptcy law who are holders of the notes, within one year after we issue the notes), and the court determines that we were insolvent at the time of the closing (under the preference laws, we would be presumed to have been insolvent on and during the 90 days immediately preceding the date of filing of any bankruptcy petition), the court could find that the incurrence of the obligations under the notes involved a preferential transfer. In addition, to the extent that certain of our collateral is not perfected until after closing, such 90-day preferential transfer period would begin on the date of perfection. If the court determined that the granting of the security interest was therefore a preferential transfer, which did not qualify for any defense under bankruptcy law, then holders of the notes would be unsecured creditors with claims that ranked *pari passu* with all other unsecured creditors of the applicable obligor, including trade creditors. In addition, under such circumstances, the value of any consideration holders received pursuant to the notes, including upon foreclosure of the collateral securing the notes and the guarantees, could also be subject to recovery from such holders and possibly from subsequent assignees, or such holders might be returned to the same position they held as holders of the notes.

The notes currently have no established trading or other public market, and an active trading market may not develop for the notes. The failure of a market to develop for the notes could affect the liquidity and value of the notes and you may not be able to sell the notes readily, or at all, or at or above the price that you paid.

The notes constitute a new issue of securities with no established trading market. We do not intend to apply for the notes to be listed on any securities exchange or to arrange for quotation on any automated dealer quotation system. A market may not develop for the notes, and you may not be able to sell any of your notes at a particular time, at favorable prices or at all. As a result, we cannot assure you as to the liquidity of any trading market for any of the notes. Accordingly, you may be required to bear the financial risk of your investment in the notes indefinitely. If a trading market were to develop, future trading prices of the notes may be volatile and will depend on many factors, including:

- our operating performance and financial condition or prospects;

the prospects for a company in our industry generally;

the number of holders of the notes;

prevailing interest rates;

the interest of securities dealers in making a market for the notes; and

the market for similar securities and the overall securities market.

The trading price of the notes may be volatile.

Historically, the market for non-investment grade debt, such as the notes, has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. Any such disruptions could adversely affect the prices at which you may sell your notes. In addition, the notes may trade at a discount from the initial offering price of the notes, depending on the prevailing interest rates, the market for similar notes, our performance and other factors, many of which are beyond our control.

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;

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pollution and other environmental damage;

clean-up responsibilities;

regulatory investigations and penalties;

suspension of our operations; and

repairs to resume operations.

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

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

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

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

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

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

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

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

changes in the regulatory environment.

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

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

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

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

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

domestic and foreign supplies of oil and natural gas;

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

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

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

level of global oil and natural gas inventories;

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

weather conditions;

technological advances affecting oil and natural gas production and consumption;

overall U.S. and global economic conditions; and

price and availability of alternative fuels.

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

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

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

As of December 31, 2013, 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. 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. While we received additional debt financing during the fourth quarter of 2013, at December 31, 2013, 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 transition zone acreage. The cost of exploration of such prospects, even when limited to our proportionate interest in such costs, is likely beyond that which we could fund from our current financial resources. Accordingly, we intend to seek partners to absorb a substantial portion of our share of such exploration costs. To that end, we have 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, 2013, 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 participation of partners in the financing and development of those prospects and subjects us to risk associated with operating under BOEMRE rules.

During 2013, we acquired four leases totaling 19,814 acres in the shallow Gulf of Mexico shelf. The leases are located in the federal waters of the Gulf of Mexico and are subject to rules and regulations of the BOEMRE. 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 Deepwater Horizon incident, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry suffered damage from Hurricanes Ivan, Katrina, Rita, Gustav, Ike and Isaac. As a result, insurance costs for many operators in the Gulf Coast region have increased significantly from the costs that similarly situated participants in this industry have historically incurred. Insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major wind storm in the event that damages are incurred. If storm activity in the future is as severe, insurance underwriters may no longer insure assets in the Gulf Coast region against weather-related damage. In addition, we do not intend to put in place business interruption insurance due to its high cost. This insurance may not be economically available in the future, which could adversely impact business prospects in the Gulf Coast region and adversely impact our operations. If an accident or other event resulting in damage to our operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a vendor, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

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

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

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

This prospectus 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.

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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 95% of our proved reserves, but do not expect to operate any wells that may be drilled on ultra-deep prospects or the Gulf of Mexico shelf prospects acquired during 2013. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

the timing and amount of capital expenditures;

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

the operator s expertise and financial resources;

approval of other participants in drilling wells;

selection of technology; and

the rate of production of the reserves.

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

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

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

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

Two customers accounted for approximately 89% of our total oil and natural gas revenues during the year ended December 31, 2013. Our inability to continue to sell our production to those customers, if not offset by sales with new or other existing customers, could have a material adverse effect on our business and operations.

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

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

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

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

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

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

Risks Related to Our Risk Management Activities

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

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

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

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

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

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

production is less than expected;

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

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

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

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

Risks Related to Our Acquisition Strategy

Our acquisitions may be stretching our existing resources.

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

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

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

operating a larger organization;

coordinating geographically disparate organizations, systems and facilities;

integrating corporate, technological and administrative functions;

diverting management s attention from other business concerns;

diverting financial resources away from existing operations;

an increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

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

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

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

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

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

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

acceptable prices for available properties;

amounts of recoverable reserves;

estimates of future oil and natural gas prices;

estimates of future exploratory, development and operating costs;

estimates of the costs and timing of plugging and abandonment; and

estimates of potential environmental and other liabilities.

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

Risks Related to Our Indebtedness and Access to Capital and Financing

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

As of December 31, 2013, we had total indebtedness of $179.8 million. Our leverage and the current and future restrictions contained in the agreements governing our indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Our indebtedness and other financial obligations and restrictions could have financial consequences. For example, they could:

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

increase our vulnerability to general adverse economic and industry conditions;

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

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

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

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

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

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

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

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

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

refinance all or a portion of our debt;

obtain additional financing;

sell some of our assets or operations;

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

revise or delay our strategic plans.

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

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

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

incur dividend or other payment obligations;

incur indebtedness and issue preferred stock; or

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

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

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

We expect to make substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our capital requirements depend on numerous factors and we cannot predict accurately the timing and amount of our capital requirements. We have historically financed our capital expenditures through cash flow from operations and cash on hand, including cash received through multiple equity and debt offerings undertaken during 2011, 2012 and 2013. However, if our capital requirements vary materially from those provided for in our current projections, we may require additional financing to support future capital expenditures. At December 31, 2013, 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.

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

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

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

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

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

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

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

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

THE EXCHANGE OFFER

Purpose of the Exchange Offer

We sold the outstanding notes in transactions that were exempt from or not subject to the registration requirements of the Securities Act. Accordingly, the outstanding notes are subject to transfer restrictions. In general, you may not offer or sell the outstanding notes unless either they are registered under the Securities Act or the offer or sale is exempt from or not subject to registration under the Securities Act and applicable state securities laws.

In connection with the sale of the outstanding notes, we entered into a registration rights agreement with the purchasers of the outstanding notes. We are offering the exchange notes under this prospectus in an exchange offer for the outstanding notes to satisfy our obligations under the registration rights agreement. The exchange offer will be open for at least 30 days (or longer, if required by applicable law). During the exchange offer period, we will exchange the exchange notes for all outstanding notes properly surrendered and not withdrawn before the expiration date. The exchange notes will be registered and the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding notes will not apply to the exchange notes.

Resale of Exchange Notes

Based on no-action letters of the SEC staff issued to third parties, we believe that exchange notes may be offered for resale, resold and otherwise transferred by you without further compliance with the registration and prospectus delivery provisions of the Securities Act if:

- you are not an affiliate of us or any of the subsidiary guarantors within the meaning of Rule 405 under the Securities Act;
- such exchange notes are acquired in the ordinary course of your business; and
- you do not intend to participate in a distribution of the exchange notes and you have no arrangement or understanding with any person or entity to participate in the distribution of the exchange notes.

The SEC staff, however, has not considered the exchange offer for the exchange notes in the context of a no-action letter, and the SEC staff may not make a similar determination as in the no-action letters issued to these third parties.

If you tender in the exchange offer with the intention of participating in any manner in a distribution of the exchange notes, you

- cannot rely on such interpretations by the SEC staff; and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction.

Unless an exemption from registration is otherwise available, any securityholder intending to distribute exchange notes must be covered by an effective registration statement under the Securities Act. The registration statement should contain the selling securityholder s information required by Item 507 or 508, as applicable, of Regulation S-K under the Securities Act.

This prospectus may be used for an offer to resell, resale or other transfer of exchange notes only as specifically described in this prospectus. If you are a broker-dealer, you may participate in the exchange offer only if you acquired the outstanding notes as a result of market-making activities or other trading activities. Each broker-dealer that receives exchange notes for its own account in exchange for outstanding notes, where such outstanding notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge by way of the letter of transmittal that it will deliver this prospectus in connection with any resale of the exchange notes. Please read the section captioned Plan of Distribution for more details regarding the transfer of exchange notes.

Terms of the Exchange Offer

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any outstanding notes properly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date of the exchange offer. We will issue exchange notes in principal amount equal to the principal amount of outstanding notes surrendered in the exchange offer. Outstanding notes may be tendered only for exchange notes and only in denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The exchange offer is not conditioned upon any minimum aggregate principal amount of outstanding notes being tendered in the exchange offer.

As of the date of this prospectus, $54,600,000 in aggregate principal amount of 10.0% Senior Secured Notes due 2015 are outstanding. This prospectus is being sent to the registered holders of the outstanding notes. There will be no fixed record date for determining registered holders of outstanding notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the rules and regulations of the SEC. Outstanding notes whose holders do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These outstanding notes will be entitled to the rights and benefits such holders have under the indenture governing the outstanding notes and the registration rights agreement.

We will be deemed to have accepted for exchange properly tendered outstanding notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the exchange notes from us.

If you tender outstanding notes in the exchange offer, you will be responsible for brokerage fees and commissions, transfer taxes and the fees and expenses of any legal counsel and any other advisors you engage with respect to the exchange of outstanding notes. Please read Fees and Expenses for more details regarding fees and expenses that we expect to pay in connection with the exchange offer.

We will return any outstanding notes that we do not accept for exchange for any reason without expense to their tendering holders promptly after the expiration or termination of the exchange offer.

Expiration Date

The exchange offer will expire at 5:00 p.m., New York City time, on , 2014, unless, in our sole discretion, we extend it.

Extensions, Delays in Acceptance, Termination or Amendment

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any outstanding notes by giving oral or written notice of such extension to the holders at any time until the exchange offer expires or terminates. During any such extensions, all outstanding notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

To extend the exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the holders of outstanding notes of the extension via a press release issued no later than 9:00 a.m. New York City time on the business day after the previously scheduled expiration date.

If any of the conditions described below under Conditions to the Exchange Offer have not been satisfied, we reserve the right, in our sole discretion

- to delay accepting for exchange any outstanding notes,
- to extend the exchange offer, or
- to terminate the exchange offer,

by giving oral or written notice of such delay, extension or termination to the exchange agent. Subject to the terms of the registration rights agreement, we also reserve the right to amend the terms of the exchange offer in any manner.

Any such delay in acceptance, extension, termination or amendment will be followed promptly by oral or written notice thereof to holders of the outstanding notes. If we amend the exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The prospectus supplement will be distributed to holders of the outstanding notes. Depending upon the significance of the amendment and the manner of disclosure to holders, we will extend the exchange offer if it would otherwise expire during such period. If an amendment constitutes a material change to the exchange offer, including the waiver of a material condition, we will extend the exchange offer, if necessary, to remain open for at least five business days after the date of the amendment. In the event we offer any consideration for the outstanding notes or in the percentage of outstanding notes being sought by us, we will extend the exchange offer to remain open for at least 10 business days after the date we provide notice of such increase or decrease to the registered holders of outstanding notes.

Conditions to the Exchange Offer

We will not be required to accept for exchange, or exchange any exchange notes for, any outstanding notes if the exchange offer, or the making of any exchange by a holder of outstanding notes, would violate applicable law or SEC policy. Similarly, we may terminate the exchange offer as provided in this prospectus before accepting outstanding notes for exchange in the event of such a potential violation.

We will not be obligated to accept for exchange the outstanding notes of any holder that has not made to us the representations described under Procedures for Tendering and Plan of Distribution and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the exchange notes under the Securities Act.

Additionally, we will not accept for exchange any outstanding notes tendered, and will not issue exchange notes in exchange for any such outstanding notes, if at such time any stop order has been threatened or is in effect with respect to the exchange offer registration statement of which this prospectus constitutes a part or the qualification of the indenture under the Trust Indenture Act of 1939.

We expressly reserve the right to amend or terminate the exchange offer, and to reject for exchange any outstanding notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offer specified above. We will promptly give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the outstanding notes.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times prior to the expiration of the exchange offer in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an ongoing right that we may assert at any time or at various times prior to the expiration of the exchange offer.

Procedures for Tendering

To participate in the exchange offer, you must properly tender your outstanding notes to the exchange agent as described below. We will only issue exchange notes in exchange for outstanding notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the outstanding notes, and you should follow carefully the instructions on how to tender your outstanding notes. It is your responsibility to properly tender your outstanding notes. We have the right to waive any defects. However, we are not required to waive defects, and neither we nor the exchange agent is required to notify you of any defects in your tender.

There is no procedure for guaranteed later delivery of the outstanding notes.

Only a holder of record may tender outstanding notes in the exchange offer. To tender in the exchange offer, a holder must:

complete, sign and date the letter of transmittal, or a facsimile of the letter of transmittal; have the signature on the letter of transmittal guaranteed if the letter of transmittal so requires; and deliver the letter of transmittal or facsimile, together with all other documents required by such letter of transmittal, to the exchange agent prior to the expiration date; or

comply with DTC s Automated Tender Offer Program procedures described below.

In addition, either:

- the exchange agent must receive, before expiration of the exchange offers, the tendered old notes along with the letter of transmittal; or
- the exchange agent must receive, before expiration of the exchange offers, a properly transmitted agent s message or a timely confirmation of book-entry transfer of old notes into the exchange agent s account at DTC according to the procedure for book-entry transfer described below.

To be tendered effectively, the exchange agent must receive any physical delivery of the letter of transmittal and other required documents at the address set forth below under the caption Exchange Agent before expiration of the exchange offer. To receive confirmation of valid tender of outstanding notes, a holder should contact the exchange agent at the telephone number listed under the caption Exchange Agent.

The tender by a holder that is not withdrawn before expiration of the exchange offer will constitute an agreement between that holder and us in accordance with the terms and subject to the conditions set forth in this prospectus and in the letter of transmittal. If a holder tenders less than all of the outstanding notes held by such holder, such tendering holder should fill in the applicable box of the letter of transmittal. The amount of outstanding notes delivered to the exchange agent will be deemed to have been tendered unless otherwise indicated.

THE METHOD OF DELIVERY OF OUTSTANDING NOTES, THE LETTER OF TRANSMITTAL AND ALL OTHER REQUIRED DOCUMENTS TO THE EXCHANGE AGENT IS AT THE HOLDER S ELECTION AND RISK. RATHER THAN MAIL THESE ITEMS, WE RECOMMEND THAT HOLDERS USE AN OVERNIGHT OR HAND DELIVERY SERVICE. IN ALL CASES, HOLDERS SHOULD ALLOW SUFFICIENT TIME TO ASSURE DELIVERY TO THE EXCHANGE AGENT BEFORE EXPIRATION OF THE EXCHANGE OFFER. HOLDERS SHOULD NOT SEND THE LETTER OF TRANSMITTAL OR OUTSTANDING NOTES TO US. HOLDERS MAY REQUEST THEIR RESPECTIVE BROKERS, DEALERS, COMMERCIAL BANKS, TRUST COMPANIES OR OTHER NOMINEES TO EFFECT THE ABOVE TRANSACTIONS FOR THEM.

Any beneficial owner whose outstanding notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and who wishes to tender should contact the registered holder promptly and instruct it to tender on the owner s behalf. If the beneficial owner wishes to tender on its own behalf, it must, prior to completing and executing the letter of transmittal and delivering its old notes, either:

- make appropriate arrangements to register ownership of the outstanding notes in the owner s name; or
- obtain a properly completed bond power from the registered holder of outstanding notes.

The transfer of registered ownership may take considerable time and may not be completed prior to the expiration date.

If the applicable letter of transmittal is signed by the record holder(s) of the outstanding notes tendered, the signature must correspond with the name(s) written on the face of the outstanding note without alteration, enlargement or any change whatsoever. If the applicable letter of transmittal is signed by a participant in DTC, the signature must correspond with the name as it appears on the security position listing as the holder of the outstanding notes.

A signature on a letter of transmittal or a notice of withdrawal must be guaranteed by an eligible guarantor institution. Rule 17Ad-15 under the Exchange Act describes eligible guarantor institutions as banks, brokers, dealers, municipal securities dealers, municipal securities brokers, government securities dealers, government securities brokers, credit unions, national securities exchanges, registered securities associations, clearing agencies and savings associations. The signature need not be guaranteed by an eligible guarantor institution if the outstanding notes are tendered:

- by a registered holder who has not completed the box entitled Special Registration Instructions or Special Delivery Instructions on the letter of transmittal; or

- for the account of an eligible institution.

If the letter of transmittal is signed by a person other than the registered holder of any outstanding notes, the outstanding notes must be endorsed or accompanied by a properly completed bond power. The bond power must be signed by the registered holder as the registered holder s name appears on the outstanding notes and an eligible institution must guarantee the signature on the bond power.

If the letter of transmittal or any outstanding notes or bond powers are signed by trustees, executors, administrators, guardians, attorneys-in-fact, officers of corporations or others acting in a fiduciary or representative capacity, these persons should so indicate when signing. Unless we waive this requirement, they should also submit evidence satisfactory to us of their authority to deliver the letter of transmittal.

The exchange agent and DTC have confirmed that any financial institution that is a participant in DTC s system may use DTC s Automated Tender Offer Program to tender. Participants in the program may, instead of physically completing and signing the letter of transmittal and delivering it to the exchange agent, transmit their acceptance of the exchange offers electronically. They may do so by causing DTC to transfer the outstanding notes to the exchange agent in accordance with its procedures for transfer. DTC will then send an agent s message to the exchange agent. The term agent s message means a message transmitted by DTC, received by the exchange agent and forming part of the book-entry confirmation, to the effect that:

DTC has received an express acknowledgment from a participant in its Automated Tender Offer Program that is tendering outstanding notes that are the subject of the book-entry confirmation;

the participant has received and agrees to be bound by the terms of the letter of transmittal; and

the agreement may be enforced against the participant.

Determinations Under the Exchange Offer. We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered outstanding notes and withdrawal of tendered outstanding notes. Our determination will be final and binding. We reserve the absolute right to reject any outstanding notes not properly tendered or any outstanding notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular outstanding notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of outstanding notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of outstanding notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of outstanding notes will not be deemed made until such defects or irregularities have been cured or waived. Any outstanding notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder promptly following the expiration date of the exchange.

When We Will Issue Exchange Notes. In all cases, we will issue exchange notes for outstanding notes that we have accepted for exchange under the exchange offer only after the exchange agent timely receives:

outstanding notes or a timely book-entry confirmation that outstanding notes have been transferred into the exchange agent s account at DTC; and a properly completed and duly executed letter of transmittal and all other required documents or a properly transmitted agent s message.

Your Representations to Us. By signing the letter of transmittal, each tendering holder of outstanding notes will represent to us that, among other things:

the holder has full power and authority to tender, sell, assign and transfer the outstanding notes and to acquire the exchange notes issuable upon the exchange of the tendered outstanding notes, and when the same are accepted for exchange, the Company will acquire good and unencumbered title to the tendered outstanding notes, free and clear of all liens, restrictions, charges and encumbrances and not subject to any adverse claim;

any exchange notes that the holder receives will be acquired in the ordinary course of its business;

the holder has no arrangement or understanding with any person or entity to participate in the distribution of the exchange notes;

if the holder is not a broker-dealer, it is not engaged in and does not intend to engage in the distribution of the exchange notes;

if the holder is a broker-dealer that will receive exchange notes for its own account in exchange for outstanding notes that were acquired as a result of market-making activities or other trading activities, it will deliver a prospectus, as required by law, in connection with any resale of those exchange notes (see Plan of Distribution); and

the holder is not an affiliate as defined in Rule 405 of the Securities Act, of us or if the holder is an affiliate, it will comply with any applicable registration and prospectus delivery requirements of the Securities Act.

Book-Entry Transfers

The exchange agent will make a request to establish an account with respect to the outstanding notes at DTC for purposes of the exchange offers promptly after the date of this prospectus. Any financial institution participating in DTC s system may make book-entry delivery of outstanding notes by causing DTC to transfer outstanding notes into the exchange agent s account at DTC in accordance with DTC s procedures for transfer.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, holders of outstanding notes may withdraw their tenders at any time before expiration of the exchange offer.

For a withdrawal to be effective:

the exchange agent must receive a written notice of withdrawal, which may be by telegram, telex, facsimile transmission or letter, at one of the addresses set forth below under the caption Exchange Agent ; or

holders must comply with the appropriate procedures of DTC s Automated Tender Offer Program system.

Any notice of withdrawal must:

specify the name of the person who tendered the outstanding notes to be withdrawn;

identify the outstanding notes to be withdrawn, including the principal amount of the outstanding notes to be withdrawn; and

where certificates for outstanding notes have been transmitted, specify the name in which the outstanding notes were registered, if different from that of the withdrawing holder.

If certificates for outstanding notes have been delivered or otherwise identified to the exchange agent, then, prior to the release of those certificates, the withdrawing holder must also submit:

- the serial numbers of the particular certificates to be withdrawn; and
- a signed notice of withdrawal with signatures guaranteed by an eligible institution, unless the withdrawing holder is an eligible institution.

If outstanding notes have been tendered pursuant to the procedure for book-entry transfer described above, any notice of withdrawal must specify the name and number of the account at DTC to be credited with the withdrawn outstanding notes and otherwise comply with the procedures of the facility.

We will determine all questions as to the validity, form and eligibility, including time of receipt, of notices of withdrawal, and our determination shall be final and binding on all parties. We will deem any outstanding notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer. We will return any outstanding notes that have been tendered for exchange but that are not exchanged for any reason to their holder without cost to the holder. In the case of outstanding notes tendered by book-entry transfer into the exchange agent s account at DTC according to the procedures described above, those outstanding notes will be credited to an account maintained with DTC for outstanding notes, as soon as practicable after withdrawal, rejection of tender or termination of the exchange offers. You may retender properly withdrawn outstanding notes by following one of the procedures described under the caption Procedures for Tendering above at any time on or before expiration of the exchange offer.

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by e-mail, telephone or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer-manager in connection with the exchange offer and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out-of-pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

- SEC registration fees;
- fees and expenses of the exchange agent and trustee;
- accounting and legal fees and printing costs; and
- related fees and expenses.

Transfer Taxes

Each tendering holder will pay all transfer taxes, if any, applicable to the exchange of outstanding notes under the exchange offer.

Consequences of Failure to Exchange

If you do not exchange your outstanding notes for exchange notes under the exchange offer, the outstanding notes you hold will continue to be subject to the existing restrictions on transfer. In general, you may not offer or sell the outstanding notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not intend to register outstanding notes under the Securities Act unless the registration rights agreement requires us to do so.

Any tenders of outstanding notes under the exchange offer will reduce the principal amount of the currently outstanding notes. Due to the corresponding reduction in liquidity, this may have an adverse effect upon, and increase the volatility of, the market price of any currently outstanding notes that you continue to hold following completion of the exchange offer.

Accounting Treatment

We will record the exchange notes in our accounting records at the same carrying value as the outstanding notes. This carrying value is the face value of the outstanding notes, less the original issue discount (net of amortization) as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer, other than the recognition of the fees and expenses of the offering as stated under Fees and Expenses.

Other

Participation in the exchange offer is voluntary, and you should consider carefully whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered outstanding notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any outstanding notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered outstanding notes.

Exchange Agent

The Bank of New York Mellon Trust Company, N.A. has been appointed as exchange agent for the exchange offer. You should direct questions and requests for assistance and requests for additional copies of this prospectus or of the letter of transmittal or the notice of withdrawal to the exchange agent addressed as follows:

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A.

c/o The Bank of New York Mellon Trust Corporation

Corporate Trust Operations Reorganization Unit

111 Sanders Creek Parkway

East Syracuse, NY 13057

Attention: Dacia Brown-Jones

Facsimile Transmission

(732) 667-9408

Confirm by Telephone:

(315) 414-3349

USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement. We will not receive any cash proceeds from the issuance of the exchange notes in the exchange offer. In consideration for issuing the exchange notes as contemplated by this prospectus, we will receive outstanding notes in a like principal amount. The form and terms of the exchange notes are identical in all respects to the form and terms of the outstanding notes, except the exchange notes do not include certain transfer restrictions, registration rights or provisions for additional interest. Outstanding notes surrendered in exchange for the exchange notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the exchange notes will not result in any change in our outstanding indebtedness.

MANAGEMENT DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION 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, 2013, our properties consisted of 52,103 acres under lease, including 32,289 acres gross/net located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana and 19,814 acres gross/net under federal leases in the shallow Gulf of Mexico shelf.

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

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

As of December 31, 2013, our total proved reserves were 17.2 MMBoe, consisting of 9.2 MMBbls of oil and 48.0 Bcf of natural gas, approximately 84% of which was attributable to state and parish properties. The PV-10 of our proved reserves at December 31, 2013 was $410.8 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $357.7 million. Additionally, we had probable reserves of 16.8 MMBoe, consisting of 6.9 MMBbls of oil and 59.5 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities. We operate over 95% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

During 2013, we produced 803.4 MBoe, of which approximately 75% was oil and all of which was attributable to our state and parish properties. As of December 31, 2013, our development opportunities included 53 proved behind pipe and shut-in opportunities in 33 wells in 6 fields, 88 proved undeveloped opportunities within 24 proposed wells in 7 fields and 29 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2013, we had 45 probable undeveloped opportunities within 26 wells in 6 fields, 20 possible behind pipe and shut-in development opportunities and 78 possible undeveloped opportunities within 35 proposed wells in 5 fields. During the year ended December 31, 2013, we successfully completed 4 development wells, 1 of which was completed as a dual completion, 17 recompletions and 9 workovers.

Recent Developments

The following significant events, among others, affected our operations and financial position during 2012 and 2013:

Drilling and Development Activities

During 2013 and 2012, we invested $31.4 million and $59.8 million, respectively, in our drilling and development program and infrastructure projects, summarized as follows:

Development Drilling. During 2013 and 2012, we drilled four and three development wells, respectively.

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

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

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

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

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

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

Infrastructure Program. During 2013 and 2012, we invested $5.6 million and $3.5 million, respectively, in infrastructure improvements and additions to support existing production and anticipated increases in production.

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.

In addition to our program of proved undeveloped, PDNP, recompletion and workover opportunities, during 2013 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 acquired four leases totaling 19,814 acres in the shallow Gulf of Mexico shelf. 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 2014, 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 and Tropical Storm Karen

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.

In early October 2013, we were substantially 100% shut-in for a day as pipeline operators and other third party service providers temporarily ceased operations in the Gulf of Mexico as a precaution prior to the arrival of Tropical Storm Karen. No material damage was sustained as a result of the storm but it took five days to bring our properties back to full production. As a result, we experienced some deferral of production and associated revenues during the fourth quarter, estimated at 6 MBbls based on pre-storm production.

Leasehold and Seismic Activity

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

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

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

Hedges

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, ratio swaps and covered calls to mitigate exposure to commodity price movements, but not for trading or speculative purposes. As of December 31, 2013, we had in place (i) fixed price swaps covering an aggregate of 1,000 barrels of oil per day, or an aggregate of 90,000 barrels of oil over the period beginning January 2014 and ending March 2014, at prices ranging from $105.18 to $109.20 per barrel and (ii) covered calls covering an aggregate of 500 barrels of oil per day, or an aggregate of 91,250 barrels of oil over the period beginning September 1, 2014 and ending March 31, 2015, at a strike price of $103.30.

Compensation

Our board of directors has adopted an Annual Incentive Program which is intended to establish potential bonus payouts tied to satisfaction of performance criteria and established broad company performance criteria. $190,553 of compensation expense was reported during 2012, based on accrual of estimated bonus payments under the program. No bonuses were accrued or paid with respect to 2013.

Stock Option Activity

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

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.

During 2013, we granted stock options to purchase an aggregate of 105,000 shares of common stock to non-employee directors. The options are exercisable at $2.18 per share, have a term of seven years and vest 50% on the grant date and 50% one year from the grant date.

In addition, during 2013, we granted stock options purchase an aggregate of 225,000 shares of common stock to employees, including options to purchase an aggregate of 90,000 shares granted to a newly hired officer. The options are exercisable at prices ranging from $1.53 to $2.42 per share.

As a result of the stock option grants, we recorded $1,001,160 of compensation charges that are reflected in general and administrative expense during the year ended December 31, 2013. During 2013, no stock options were forfeited.

As of December 31, 2013, total compensation cost related to unvested stock option awards not yet recognized in earnings was approximately $0.6 million, which is expected to be recognized over a weighted average period of approximately 0.62 years.

Share Issuances

During 2013, we sold 6,500 shares of common stock for $9,945 pursuant to the exercise of outstanding stock options and 35,000 shares for $13,850 pursuant to the exercise of outstanding stock warrants.

Sale of 10% Senior Secured Notes

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

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

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

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

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

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

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

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

In connection with the issuance and sale of the First Lien Notes, we and the Guarantors entered into a registration rights agreement (the Registration Rights Agreement) with the Purchasers. Pursuant to the Registration Rights Agreement, we and the Guarantors agreed to file a registration statement with the Securities and Exchange Commission (SEC) so that holders of the First Lien Notes can exchange the First Lien Notes for registered notes that have substantially identical terms as the First Lien Notes. In addition, we and the Guarantors agreed to exchange the guarantee related to the First Lien Notes for a registered guarantee having substantially the same terms as the original guarantee. We filed the required registration statement in January 2014 and, as of this writing, the SEC has not yet declared the registration statement effective.

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 2013 year-end reserve report, we used an average oil price of $108.69 per Bbl, and a natural gas price of $4.35 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, 2013 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.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil and Gas Revenue

Oil and gas revenue for the year ended 2013 decreased by 16.7% to $68.7 million from $82.5 million in 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, 2013 and 2012:

	2013	2012
Revenues		
Oil	$ 63,431,840	$ 72,959,377
Gas	5,264,215	9,569,555
Total oil and gas revenues	$ 68,696,055	$ 82,528,932
Production		
Oil (Bbls)	603,600	676,400
Gas (Mcf)	1,198,800	2,639,500
Total production (Boe)	803,400	1,116,317
Average sales price		
Oil (per Bbl)	$ 105.09	$ 107.86
Gas (per Mcf)	4.39	3.63
Total average sales price (per Boe)	$ 85.51	$ 73.93

Oil production was down 72.8 MBbl, or 10.8%, as compared to 2012. The decrease was primarily due to (i) a drop in oil production from the Grand Bay SL 195 QQ lease as a result of low gas volumes available for gas lift, (ii) flow line restrictions and facility repairs for the Catina well in Main Pass 46 Field, and (iii) curtailed production in Main Pass 25 Field due to third party product handing issues and lack of gas lift gas coupled with platform shut-in for construction projects in the third and fourth quarters, resulting in a deferral of an estimated 16 MBbl of production. Partially offsetting the production declines were (i) an increase in production from new drills in the Breton Sound 18 Field (North Tiger well) brought into production in the fourth quarter of 2012, and (ii) commencement of production in Breton Sound 32 Field (Zeke and Rocky wells) from wells brought into production in the third quarter of 2013, and in Grand Bay Field SL 195-209 (Buddy well) from a well brought into production in the first quarter of 2013.

Natural gas production was down 1,441 MMcf, or 54.5%, as compared to 2012. The decrease in gas production, outside of natural reserve declines, was primarily due to (i) flow line restrictions and facility repairs for the Catina well in Main Pass 46 Field, (ii) curtailed production in Main Pass 25 Field due to third party product handing issues and platform shut-in for construction projects in the third and fourth quarters resulting in a deferral of an estimated 55MMcf of production, (iii) the depletion of the 6100 sand in the SL 20034#1, the 6A sand in the SL 195 QQ #2D and the cib carst 2 sand in the SL 1268 #G-1 wells in Main Pass 46, Grand Bay and Main Pass 52 Fields, respectively, (iv) shut-ins in Grand Bay Field due to drilling our QQ25 well and work associated with infrastructure improvements, mechanical issues, gas lift interruption, flow line testing and repair and down time on compressors. Partially offsetting the declines in gas production, both natural reserve declines and otherwise, was increased production associated with the completion of our QQ25 wells in Grand Bay which came into production in the first quarter of 2013, increased production from SL 16392 and SL 17156 in Main Pass 46 and Vermilion 16 Fields, respectively.

The increase in realized hydrocarbon prices reflects a higher percentage of overall production being related to oil production, as well as a general strengthening of natural gas prices partially offset by a weakening of crude oil prices. We continued to realize a premium pricing on both our crude oil and natural gas production.

Oil and Gas Hedging

For 2013, we recorded a loss on oil and gas hedging of $1.7 million compared to a gain of $0.1 million in 2012. At December 31, 2013, none of our hedges met the statistical tests required to be considered effective for GAAP reporting purposes. Accordingly, unrealized non-cash losses of $1.0 million were recognized in net income.

Other Revenues

Other revenues during 2013 consisted principally of (i) production handling fees and (ii) a reversal of an over accrual relating to the settlement of the Plaquemines Parish ad valorem tax litigation and. During 2012, other revenues consisted of (i) production handling fees, and (ii) settlements of lawsuits against the former owners of The Harvest Group LLC and Harvest Oil & Gas, LLC. The decrease in other revenue was principally attributable to the one-time nature of the lawsuit settlements totaling $604,500 during 2012.

Operating Expenses

Operating expenses increased by 11.1% to $63.7 million for 2013 from $71.7 million in 2012. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2013 and 2012:

	2013		2012	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 21,685,103	$ 26.99	$ 19,317,283	$ 17.30
Workover expense	2,475,541	3.08	3,828,197	3.43
Exploration expense	900,255	1.12	547,192	0.49
Loss on plugging and abandonment	701,241	0.88	2,468,969	2.21
Dry hole costs	-	-	93,353	0.08
Depreciation, depletion and amortization	17,269,349	21.49	27,407,700	24.55
Impairment expense	2,179,075	2.71	401,752	0.36
Accretion expense	2,552,381	3.18	1,510,165	1.35
Gain on revision of asset retirement obligations	(564,719)	(0.70)	(245,007)	(0.22)
General and administrative expenses	9,253,600	11.52	8,584,486	7.69
Severance taxes	7,274,808	9.05	7,768,426	6.96
	$ 63,726,634	$ 79.32	$ 71,682,516	$ 64.21

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

Lease Operating Expense

Lease operating expenses for 2013 increased 12.3% to $21.7 million from $19.3 million in 2012 and, on a per BOE basis increased 56.0% to $26.99 per BOE from $17.31 per BOE in 2012.

The increase in operating expenses during 2013 was primarily attributable to non-recurring lease operating expenses related to the salvage of a barge in Little Bay, regulatory compliance charges for Grand Bay and cleaning of a flow line for a well in Main Pass 46. The increase in lease operating expense on a per BOE basis was primarily attributable to the increase in total lease operating expenses together with the decrease in production volumes in 2013.

Workover Expense

Workover expense for 2013 decreased 35.3% to $2.5 million from $3.8 million in 2012. The decrease in workover expense was attributable to a decrease in the number of workovers completed in 2013.

Exploration Expense

Exploration expense for 2013 increased 64.5% to $0.9 million from $0.5 million in 2012. The increase in exploration expenses principally relate to increased delay rentals and field study expenses, including delay rentals on Gulf of Mexico shelf acreage acquired during 2013 ($0.1 million) and an increase in field study expenses related to Grand Bay Field and the Gulf of Mexico shelf acreage ($0.3 million).

Loss on plugging and abandonment

Loss on plugging and abandonment decreased to $0.7 million from $2.5 million in 2012. The loss in each year reflects plugging and abandonment costs in excess of estimated costs reflected in our asset retirement obligation liabilities.

The decrease in loss reflected our 2012 determination to plug orphaned wells on expired leases in Little Bay, South Atchafalaya Bay and Crooked Bayou fields. 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. During 2013, our loss on plugging and abandonment related to a single high pressure well which we discovered had been completed with a kill string, resulting in the need for additional plugging and tubing cuts.

Dry Hole Costs

Dry hole costs decreased to $0 in 2013 from $0.1 million in 2012. 2012 dry hole costs reflect residual 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 2013 decreased 37.0% to $17.3 million from $27.4 million in 2012. The decrease in DD&A was attributable to reduced production levels and lower capital expenditures. DD&A is computed on the units-of-production method separately on each individual property and includes the accrual of future plugging and abandonment costs.

Impairment expense

Impairment expense for 2013 increased 442.4% to $2.2 million from $0.4 million in 2012. Impairment expense during 2013 related to the loss of a lease, and associated reserves, at our Little Bay Field. 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.

Accretion expense

Accretion expense for 2013 increased 69.0% to $2.6 million from $1.5 million in 2012. Accretion expense relates to our asset retirement obligations. The increase 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 $0.6 million in 2013 and $0.2 million in 2012. The gain was due primarily to downward revisions in the asset retirement obligations relating to two properties which exceeded the carrying amount of the property.

General and Administrative Expense

General and administrative expense for 2013 increased 7.8% to $9.3 million from $8.6 million in 2012. The increase in general and administrative expense was primarily attributable to contract and independent reserve engineering fees, increased legal costs and employee recruiting fees partially offset by a reduction in stock based compensation and bonuses accrued.

Severance Taxes

Severance taxes for 2013 decreased 6.4% to $7.3 million from $7.8 million in 2012. The decrease was primarily due to lower revenues partially offset by a decrease in the number of inactive wells eligible for certain Louisiana severance tax exemptions.

Other Income (Expense), Net

Net other expenses for 2013 increased 21.7% to $21.4 million from $17.6 million in 2012. The following table sets forth the components of net other income (expenses) for 2013 and 2012:

		2013		**2012**
Financing expense		-		(7,527)
Interest expense (net)		(21,449,965)		(17,619,063)
	$	(21,449,965)	$	(17,626,590)

The increase in other expense was attributable to higher interest expense attributable to our placement of an additional $25.0 million in principal amount of senior secured notes in December 2012 and the issuance of $54.6 million of 10% First Lien Notes in November 2013, partially offset by the retirement of $27.3 million of 12½% notes as part of the issuance of the 10% First Lien Notes.

Income Tax Provision (Benefit)

For 2013, we recorded an income tax provision of $8.6 million compared to a benefit of $1.8 million in 2012. The income tax provision during 2013 reflects recognition of a valuation allowance against deferred tax assets which primarily relate to our net operating loss carry-forwards.

Our effective tax rates for 2013 and **2012 were** (48.6)% and **32.1**%, 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.

Financial Condition

Liquidity and Capital Resources

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

During 2012 and 2013 we funded operations out of operating cash flow and cash on hand, which funds have been supplemented by our receipt of funds from our $20.1 million equity capital raise in May 2012, our issuance of $25 million of senior secured notes in December 2012 and our issuance of $27.3 million of First Lien Notes for cash in November 2013. During 2012 and 2013, we did not have access to available capital under a revolving credit agreement and do not at this time have a revolving credit facility. With our receipt of proceeds from our November 2013 First Lien Note offering, we do not anticipate that we will seek to establish a revolving credit facility in the foreseeable future.

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 2012 and 2013, while continuing to advance short-term objectives associated with continual investment in our infrastructure, we focused on our mid-term objectives through drilling proved undeveloped opportunities.

We believe that our cash flows from operations and cash on hand 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 operating results, including 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 or curtail our planned development of proved undeveloped opportunities or otherwise adjust the nature or rate of our development program to reflect available funding.

Pursuit of our long-term plans for exploratory drilling of deep shelf prospects in Grand Bay Field, Vermilion 16 Field and our newly acquired Gulf of Mexico shelf prospects is expected to require funding in excess of our current resources and projected operating cash flow and, with respect to ultra-deep prospects in Vermilion 16 Field, 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, 2013, we were continuing to monitor developments within the ultra-deep trend and to be engaged in efforts to attract potential partners relative to the potential exploration of our ultra-deep prospects and deep shelf prospects. Even if we are able to attract partners to bear the majority of the costs of exploration of these prospects, we may lack the financial resources to carry our proportionate share of the anticipated exploration and development costs associated with such joint venture and may be required to secure additional financing to support our share of such costs and maintain our interest in such ultra-deep and deep shelf 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.

Cash, Cash Flows and Working Capital

We had a cash balance of $32.5 million and working capital of $20.4 million at December 31, 2013 as compared to a cash balance of $32.3 million and working capital of $21.2 million at December 31, 2012. The change in cash on hand and working capital is primarily attributable to the receipt of $25.3 million of net proceeds from our November 2013 First Lien Note offering and cash flows from operations and partially offset by investment in our development program and lease acquisition costs associated with our Gulf of Mexico lease and additional Louisiana state leases.

Operations provided cash flow of $7.6 million during 2013 as compared to $27.7 million during 2012. The change in operating cash flows during 2013 was principally attributable to reduced profitability resulting from lower production volumes and increased operating costs and changes in our operating assets and liabilities.

Investing activities used cash flows of $31.0 million during 2013 as compared to $56.3 million during 2012. The decrease in cash used in investing activities during 2013 was attributable to drilling of less costly wells during 2013 (4 development wells drilled during 2013 for $17.3 million as compared to 3 development wells drilled during 2012 for $39.8 million), partially offset by increased lease acquisition costs (up $1.4 million) as a result of acquisition of our Gulf of Mexico and additional State of Louisiana leases.

Financing activities provided cash flows of $23.7 million during 2013 as compared to $45.0 million during 2012. Cash flows provided by financing activities during the 2013 reflect the receipt of $25.3 million of net proceeds from our November 2013 sale of First Lien Notes, partially offset by repayments of short term notes. Cash flows provided by financing activities during 2012 reflected the receipt of funds from our 2012 equity offering ($18.4 million) and our 2012 offering of additional 2016 Notes ($23.4 million), partially offset by repayments of short term notes ($1.7 million).

Debt

At December 31, 2013, we had $178.2 million of indebtedness outstanding, consisting of $54.6 million in face amount of 10% First Lien Notes, less $0.3 million of debt discount, and $125.2 million in face amount of 12½% Senior Secured Notes due 2016 less $1.3 million of debt discount.

We had no letters of credit outstanding at December 31, 2013 that were not fully collateralized by cash.

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

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

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

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

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

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

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

Capital Expenditures

Our capital spending for 2013 was $33.9 million relating primarily to development of our oil and gas properties, including drilling 4 development wells ($17.3 million), 22 recompletions ($6.6 million), 10 workovers ($2.5 million), investments in multiple infrastructure projects ($5.6 million), acquisitions of additional leasehold acreage in the Gulf of Mexico and transitional coastline of the State of Louisiana ($1.6 million) and other leasehold costs ($0.3 million). Capital expenditures were down from $63.4 million during 2012.

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

Contractual Obligations

The following table details our long-term debt and contractual obligations as of December 31, 2013:

	Payments due by period				
	Total	**2014**	**2015 2016**	**2017 2018**	**Thereafter**
Debt (1)	$ 179,800,000	$	$ 179,800,000	$	$
Operating leases	150,833	120,666	30,167		
Capital leases					
Asset retirement obligations	56,194,500		1,420,000	4,125,000	50,649,500
Total	$ 236,145,333	$ 120,666	$ 181,250,167	$ 4,125,000	$ 50,649,500

(1)

Debt consists of amounts owing under our 10% First Lien Notes and 12½% Second Lien Notes.

Risk Management Activities   Commodity Derivative Instruments

During the third quarter of 2012, we reinstituted a hedging program and have since utilized various derivative instruments to manage our risk associated with commodity price movements. We periodically enter into price-risk management transactions (e.g., swaps, and floors) for a portion of our oil and natural gas production. In certain cases, this allows us to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. The commodity derivative instruments apply to only a portion of our production, and provide only partial price protection against declines in oil and natural gas prices, and partially limit our potential gains from future increases in prices. None of these instruments have been used for trading purposes. During 2013, we recorded an unrealized loss on commodity derivatives of $1.0 million in current earnings and an unrealized gain on commodity derivatives of $0.2 million in accumulated other comprehensive income (loss).

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2013.

Inflation

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

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, 2013, our properties consisted of 52,103 acres under lease, including 32,289 acres gross/net located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana and 19,814 acres gross/net under federal leases in the shallow Gulf of Mexico shelf.

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

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

As of December 31, 2013, our total proved reserves were 17.2 MMBoe, consisting of 9.2 MMBbls of oil and 48.0 Bcf of natural gas, approximately 84% of which was attributable to state and parish properties. The PV-10 of our proved reserves at December 31, 2013 was $410.8 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $357.7 million. Additionally, we had probable reserves of 16.8 MMBoe, consisting of 6.9 MMBbls of oil and 59.5 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities. We operate over 95% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

During 2013, we produced 803.4 MBoe, of which approximately 75% was oil and all of which was attributable to our state and parish properties. As of December 31, 2013, our development opportunities included 53 proved behind pipe and shut-in opportunities in 33 wells in 6 fields, 88 proved undeveloped opportunities within 24 proposed wells in 7 fields and 29 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2013, we had 45 probable undeveloped opportunities within 26 proposed wells in 6 fields, 20 possible behind pipe and shut-in development opportunities and 78 possible undeveloped opportunities within 35 wells in 5 fields. During the year ended December 31, 2013, we successfully completed 4 development wells, 1 of which was completed as a dual completion, 17 recompletions and 9 workovers.

Our principal and administrative offices are located at 3 Riverway, Suite 1810, 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 Limited, EPL Oil & Gas, Inc., Helis Oil and Gas Company, Hilcorp Energy Company, Swift Energy Company and Texas Petroleum Investment Company. Additionally, our shallow Gulf of Mexico shelf assets include proved reserves and prospects identified by 3-D seismic and are located in proximity to existing field infrastructure. We believe the quality and location of our properties reduce our development risk and promote operating efficiencies which help to reduce our lifting costs. Additionally, the oil produced by our assets currently commands a premium to WTI crude oil pricing. We also believe that our reserve base has significant undeveloped and exploratory drilling opportunities, which range from low to medium 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 nine other established fields on state and parish leases of south Louisiana and, to a lesser degree, in the shallow waters of the Gulf of Mexico shelf. This focused asset base allows us to leverage our technical knowledge of the geological features and operating dynamics within this region. Our geographic focus also enables us to establish economies of scale in both drilling and production operations, allowing us to manage a greater amount of acreage and minimize the marginal costs associated with development activities. Because our present operations are primarily in shallow state waters and, to a lesser extent, in the shallow Gulf of Mexico shelf, we are not exposed to the extreme risk associated with deep water operations. In addition, we are able to avoid the long lead times to first production and ultra-high costs associated with deep water development.

Extensive Workover and Drilling Inventory. At December 31, 2013, we controlled approximately 52,103 gross/net acres, of which more than half is HBP. Approximately 87% 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, 2013, our development opportunities included 53 proved behind pipe and shut-in opportunities in 33 wells in 6 fields, 88 proved undeveloped opportunities within 24 proposed wells in 7 fields and 29 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2013, we had 45 probable undeveloped opportunities within 26 proposed wells in 6 fields, 20 possible behind pipe and shut-in development opportunities and 78 possible undeveloped opportunities within 35 wells in 5 fields.

High Net Revenue Interests and Operational Control. We own an average net revenue interest in our properties of approximately 75%, which enhances our returns by reducing royalty payments and provides us flexibility in negotiating potential farm-outs, joint ventures, and other opportunities. Additionally, we own a 100% working interest in substantially all of our properties and operate over 95% of the wells that comprise our PV-10 as of December 31, 2013. 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:

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

Actively Manage the Risks and Rewards of Our Drilling Program. We operate over 95% of the wells that comprise our proved reserves as of December 31, 2013, and we own net revenue interests in our properties that average approximately 75% on a net acreage leasehold basis. We believe operating our properties is important because it allows us to control the timing and costs in our drilling budget, as well as control operating costs and production marketing. In addition, our high net revenue interests enhance our returns from each successful well we drill by generating a higher percentage of cash flow. We believe our high net revenue interests provide us with a unique opportunity to retain a substantial economic interest in riskier wells, including wells that may be drilled on the Gulf of Mexico shelf acreage, while mitigating the risk associated with these projects through farm-outs or promoted deals. Additionally, we will review and rationalize our properties on a continuous basis in order to optimize our existing asset base.

Leverage Technological Expertise. We believe that 3-D seismic analysis and other advanced technologies and production techniques are useful tools that help improve drilling results and ultimately enhance our production and returns. At December 31, 2013, we either owned or held licenses for 3-D seismic data covering over 90 square miles in Grand Bay and other fields. We intend to utilize these technologies and production techniques in exploring for, developing and exploiting oil and natural gas properties to help us reduce drilling risks, lower finding costs and provide for more efficient production of oil and natural gas from our properties. We believe that the use of these technologies enhances our probability of locating and producing reserves that might not otherwise be discovered.

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

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

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

Properties

The following table describes our properties, proved reserves and production profile at December 31, 2013:

Property	Barrels of Oil Equivalent (MBoe)	% Oil		PV-10[(1)] (in thousands)	Net Acreage (estimated)	Net Revenue Interest %	Net Producing Wells	Reserve Life Index[(2)] (Years)
Louisiana Transition Zone								
Grand Bay	6,048	68%	$	174,299	17,566	70-79%	51	31.8
Vermilion 16	4,604	32%	$	66,145	3,490	77-81%	2	*
Main Pass 46	1,026	47%	$	20,114	1,663	74-78%	4	6.1
Other	2,820	68%	$	112,972	9,570	70-82%	33	10.1
Gulf of Mexico Shelf								
Vermillion	1,669	25%	$	13,810	9,814	77%	0	*
Ship Shoal	1,072	79%	$	23,414	10,000	77%	0	*
All Properties	17,239	54%	$	410,754	52,103	70-82%	90	22.3

*

Not meaningful

(1)

Based on unweighted average benchmark prices as of the first of each month during 2013 of $96.71 per Bbl and $3.67 per MMBtu and before future income taxes. The average realized price after applying differential to unweighted average benchmark prices was $108.69 per Bbl and $4.35 per Mcf. PV-10 is a non-GAAP financial measure as defined by the SEC.

(2)

Calculated by dividing total net proved reserves by current net production for December 2013.

Louisiana Transition Zone

Our principal producing properties are located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana, an area commonly referred to as the transition zone. The majority of those properties were acquired in, and we have operated those properties since, 2008. Our properties in the transition zone span 11 fields with principal properties, by production and reserves, being in Grand Bay, Vermillion 16 and Main Pass 46 fields.

Grand Bay Field. The Grand Bay Field is located in Plaquemines Parish, approximately 70 miles southeast of New Orleans, Louisiana. It is situated in the transitional coastline in a protected in-bay environment on parish and state leases on the east side of the Mississippi River. Gulf Oil Corp. discovered the field in 1938. We are the operator of all of the Grand Bay Field with 100% working interest and net revenue interests ranging from 70% to 79%. Our leases in the Grand Bay Field, which are all HBP, cover an estimated 17,566 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 51 active wellbores, 44 proved developed nonproducing opportunities and 61 proved undeveloped opportunities in 12 proposed drilling locations within the field. There are also 21 probable developed nonproducing, 28 probable undeveloped opportunities in 17 proposed drilling locations, 18 possible developed nonproducing and 38 possible undeveloped opportunities in 23 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. More specifically, we are planning to undertake one or more reservoir simulations in the field in 2014. Based on one previous horizontal well drilled in Grand Bay field, with favorable results, we are actively seeking horizontal and high angle well candidates as part of our field study of Grand Bay field. Another important part of the study is the geopressured sequence incorporating the Tex L (25 sand) and Cib Carst (43 sand) reservoirs, below 13,000 feet, which has been largely unexplored to date. We have identified multiple opportunities within the sequence and are evaluating partnering with third parties to drill the initial prospect within the sequence.

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

During 2013, we completed the SL 195QQ-209 Buddy well in Grand Bay Field. The Buddy well was drilled during 2012 to a total depth of 6,820 feet MD/TVD and was successfully completed, in early 2013, in the 3A sand.

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 77% to 81%. The seven existing state leases cover an estimated 3,490 gross/net acres, of which 3,303 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, 2 actively producing, with 2 proved developed non-producing opportunities and 5 proved undeveloped opportunities associated with 3 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.

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

During 2013, 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.

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 78%. The four existing state leases cover an estimated 1,663 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 4 active wellbores associated with the field. All of the 10 proved undeveloped opportunities in 2 proposed new wellbores are located within Grand Bay State Lease 195.

Other Fields. We hold interests in 8 other fields in shallow waters on state leases in Plaquemines, St. Bernard and St. Mary parishes of southern Louisiana. We have a 100% working interest in all fields, except for the Main Pass 47 Field where we have a 7.5% overriding royalty interest in one producing well. Our net revenue interests in these fields average 75%. The leases, which are mostly HBP, cover 9,570 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. We have reprocessed parts of this 3-D dataset in 2013.

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

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

Gulf of Mexico Shelf.

In July 2013, final leases were awarded pursuant to our high bid on four leases, with seismic maps included, totaling 19,815 acres in the Central Gulf of Mexico Lease Sale 227. The acreage is in the shallow Gulf of Mexico shelf in water depths of 13 to 77 feet. Two of the leases are in the Vermilion area and two of the leases are in the Ship Shoal area. The leases have a primary term of five years and can be extended for an additional three years. Lease bonuses on the prospects totaled $880,000 and we paid a prospect fee of $500,000 to a third party consultant. The cost of the leases, in the amount of $1,380,000, has been recorded in oil and gas properties. Annual rentals on the leases total $138,698 during the primary term.

Using 3-D surveys included with the leases, four initial prospects have been identified within the Gulf of Mexico shelf acreage. We are seeking partners to drill the first of the prospects during 2014. The acreage includes proved undeveloped reserves at December 31, 2013 of 2.74 MMBOE.

Field Infrastructure

We own significant infrastructure assets that are used to service our properties and third-party customers, including over 100 miles of pipeline connecting several of the fields as well as outlying wellheads. There are five platform facilities plus 36 active producing wellbores associated with the Main Pass and Breton Sound fields and one platform at Vermilion 16 field. Facilities at the Grand Bay Field include four tank batteries, a compressor station, various flow lines and a bunk house and there are 51 active wellbores in the field. In addition to serving our wells and improving field economics, we generate processing and production handling revenues from third-party customers. We also operate approximately ten saltwater disposal wells.

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2013, our estimated net proved oil and natural gas reserves, the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (PV-10) and after future income taxes (Standardized Measure) of our proved reserves and our estimated net probable and possible oil and natural gas reserves, each prepared in accordance with assumptions prescribed by the Securities and Exchange Commission (SEC). All of our reserves are located in the United States.

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

		Reserves(1)		
Reserve category	**Oil (MBbls)**	**Natural Gas (MMcf)**		**Total(2)** (MBoe)
Proved				
Developed				
Producing	1,969	1,439		2,209
Shut-in	64	990		229
Behind Pipe	1,213	4,452		1,955
Total Proved Developed	3,246	6,881		4,393
Undeveloped	5,993	41,116		12,846
Total Proved	9,239	47,997		17,239
Probable(3)				
Developed	851	4,057		1,527
Undeveloped	6,008	55,426		15,246
Possible(3)				
Developed and Undeveloped	18,999	124,365		39,727
PV-10(1) (in thousands) of proved			$	410,754
Standardized Measure(4) (in thousands)			$	300,790

(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, 2013. 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, 2013 which were $96.71 per Bbl and $3.67 per MMBtu. The prices utilized for purposes of estimating our proved reserves were $108.69 per Bbl and $4.35 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 2013 12-month average prices reflected in our reported reserve estimates and the NYMEX strip prices as of December 31, 2013.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)[1]	PV-10 (in thousands)
SEC Case	9,239	47,997	17,239	$410,754
NYMEX Strip Price Case[2]	9,184	47,938	17,174	$357,664

(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, 2013, as benchmark prices for 2013 through 2019, and continued to use the 2019 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 $93.47 per barrel of oil and $5.08 per Mcf of natural gas over the remaining life of the proved reserves. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 and Standard Measure estimates set forth above were prepared by Collarini Associates for our transition zone reserves and by DeGolyer and MacNaughton for our Gulf of Mexico shelf reserves.

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

We maintain an internal staff of engineering and geoscience professionals, supplemented by consultants, who work closely with Collarini Associates and DeGolyer and MacNaughton (the outside reserve engineers) in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy and timeliness of the methods and assumptions used in this process. Our technical team members meet with outside reserve engineers periodically throughout the year to discuss the assumptions and methods used in the reserve estimation process. We provide historical information to the outside reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. 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 40 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 the outside reserve engineers in support of the reserve estimation process and to assure that information derived from the outside reserve engineers reports is properly disclosed in our reports.

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

DeGolyer and MacNaughton is an independent Dallas-based professional engineering firm providing reserve engineering and other services to the oil and gas industry worldwide. Their report was prepared under the direction of Gregory Graves, Senior Vice President. Mr. Graves holds a B.S. in petroleum engineering from the University of Texas, completed post-baccalaureate studies in micro- and macroeconomics at the University of Houston, is a licensed professional engineer and a member of the Society of Petroleum Evaluation Engineers. Mr. Graves has more than 30 years of experience in the energy industry.

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.

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

Proved Undeveloped Reserves

Our proved undeveloped reserves accounted for approximately 75% of our total reserves at December 31, 2013. As of December 31, 2013, none of our proved reserved had been classified as proved undeveloped for more than five years and the majority of the properties for which we have proved undeveloped reserves have ongoing production from currently developed zones. The following table summarizes activity within our proved undeveloped reserve category for the years ended December 31, 2013 and 2012:

	2013	**2012**
Proved undeveloped reserves (MBoe):		
Beginning of year	12,890	14,704
Transferred to proved developed through drilling	728	1,115
Increase (decrease) due to evaluation reassessments and drilling results, net	(1,073)	(2,929)
Acquisitions (dispositions), net (1)	2,740	-
Reductions of proved undeveloped reserves aged five or more years (2)	(2,439)	-
End of year	12,846	12,890

(1)

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

(2)

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

Our proved undeveloped reserves at December 31, 2013 were associated with our Louisiana properties (10,106 MMBoe) and our Gulf of Mexico shelf properties (2,740 MMBoe).

We incurred costs relating to the development of proved undeveloped reserves of $17.3 million and $39.8 million during 2013 and 2012, respectively.

All proved undeveloped locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2018. 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, 2013.

	2011	2012	2013
Net Production:			
Oil (Bbl)	605,900	676,400	603,600
Natural gas (Mcf)	2,038,000	2,639,500	1,198,800
Combined volumes (Boe)	945,567	1,116,317	803,400
Average sales price per Boe	$ 80.54	$ 73.93	$ 85.51
Average production cost per Boe(1)	$ 20.93	$ 20.74	$ 30.07

(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 a 100% success rate on all drilling over the last two years.

	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	0	0	0	0	0	0
Unproductive	1	1	0	0	0	0
Total	1	1	0	0	0	0
Developmental Wells:						
Productive	2	2	3	3	4	4
Unproductive	0	0	0	0	0	0
Total	2	2	3	3	4	4
Success Ratio (1)	67%	67%	100%	100%	100%	100%

(1)

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

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

In addition to the wells completed, during 2013 we successfully completed 17 out of 22 recompletion and 9 out of 10 workover operations and during 2012 we successfully completed 11 out of 12 recompletion and 16 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, 2013, there were no wells being drilled or recompletion or workover operations being conducted.

Productive Wells

The following table sets forth information with respect to our ownership interest in productive wells, all of which are located in the United States, as of December 31, 2013:

	Gross	Net
Oil wells	78	78
Gas wells	12	12
Total	90	90

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, 2013 included 6 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, 2013:

	Developed Acreage		**Undeveloped Acreage**		**Total Acreage**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Louisiana Transition Zone	31,245	31,245	1,044	1,044	32,289	32,289
Gulf of Mexico Shelf	-	-	19,814	19,814	19,814	19,814
Total	31,245	31,245	20,858	20,858	52,013	52,013

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

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

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

Marketing, Customers and Pricing

General

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

Marketing

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

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

We receive a premium price for our Light Louisiana Sweet (LLS) and Heavy Louisiana Sweet (HLS) crude oil produced. We attribute this premium pricing to the high quality and geographic location of the crude oil product. This combination of production location and crude oil quality have allowed us to sell our crude oil at prices above WTI price postings beginning in the second half of 2011 and continuing through 2013, and we anticipate that market conditions should allow us to continue to receive pricing above WTI postings into 2014. During 2013, we marketed our crude oil at prices that averaged approximately $7.19 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) and Chevron Natural Gas, Inc. and Chevron Products Company (collectively, Chevron) accounted for 57% and 32% of our consolidated sales in 2013, respectively. Sales of oil and gas production to Plains Marketing, J. P. Morgan Ventures Energy Corp. and Shell accounted for 33%, 12% and 36%, 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, 2013, we had in place the following hedging contracts:

Instrument	**Beginning Date**	**Ending Date**	**Fixed Price**	**Strike Price**	**Premium**	**Total Bbls**
Fixed Price Swap	January 1, 2014	March 31, 2014	$ 109.20	$ -	$ -	45,000
Fixed Price Swap	January 1, 2014	March 31, 2014	105.18	-	-	45,000
Covered Call	September 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	91,250
						181,250

Cargill, Incorporated and Kock Supply & Trading, LP are the counterparties to each of our present fixed price swap contracts and covered call options. 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, 2013, we had 34 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 prospectus.

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 was $1.3 million in Parish taxes. Also at issue were the increased assessment valuations for the years 2009, 2010, and 2011 brought by the Parish under the same theory. Saratoga contested 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*, in the 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. In December 2013, Saratoga and its subsidiaries entered into an Acknowledgment and Agreement with Plaquemines Parish settling all disputed ad valorem tax claims. Pursuant to the settlement, we agreed to pay $1,508,449 to settle all taxes, penalties and interest due for 2006 through 2012 and to dismiss all lawsuits, protests and appeals. The settlement amount is payable by release of $870,974 previously paid under protest and payment of four installments of $159,369 in January, April, August and December 2014.

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 2012, Saratoga concluded settlements with Barry Ray Salsbury, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer and received approximately $769,000 and the claims and counterclaims involving those defendants were dismissed. In 2012, the case with respect to the remaining defendants was removed to the U.S. District for the Southern District of Louisiana. During 2013, Henry Calongne and

Professional Oil and Gas Marketing were granted partial summary judgment and awarded $126,280 of marketing fees with said amount being placed in escrow pending final resolution of Saratoga s claims against each. Litigation is still pending as to the remaining defendants, including Brian Carl Albrecht, Professional Oil and Gas Marketing, and Henry Calongne. The claim against Mr. Albrecht has been converted to an arbitration proceeding and the claims against Mr. Calogne and Professional Oil and Gas Marketing are set for trial in March 2014.

We may from time to time be a party to lawsuits incidental to our business. Except as noted above, as of December 31, 2013, 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.

MANAGEMENT

Executive Officers

Our executive officers as of April 1, 2014, and their ages and positions as of that date, were as follows:

Name	Age	Position
Thomas F. Cooke	65	Chief Executive Officer and Chairman
Andrew C. Clifford	59	President
John Ebert	46	Vice President Finance and Business Development
Brian Daigle	54	Vice President Operations
Randal McDonald, Jr.	56	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 30 years of experience. Mr. Clifford s experience includes providing professional geological services on prospects throughout the United States and around the world as an independent consultant, as Vice President of Exploration for BHP Petroleum and as a Senior Geophysicist for BHP Petroleum, Kuwait Foreign Petroleum and Esso Exploration. Prior to joining the company, Mr. Clifford was a co-founder and Executive Vice President of Aurora Gas, LLC, an independent gas developer and producer with gas production operations in Cook Inlet, Alaska. Mr. Clifford holds a B.Sc, with honors, in Geology with Geophysics from London University and is a frequent speaker and published author on a variety of energy industry topics.

John Ebert has served as our Vice President Finance and Business Development since November 2013 after joining our company in a business development capacity in August 2013. Prior to joining our company, from 2011 to 2013, Mr. Ebert was a consulting partner in ETROA Resources, LLC, an oil and gas investment and development firm located in Covington, Louisiana and focused on Gulf Coast onshore and offshore resources. Mr. Ebert held various positions with Woodside Energy from 2005 until 2011, beginning as a senior reservoir engineer and adding the roles of Engineering Manager, Senior Manager Business Planning, and Vice President of Finance. Mr. Ebert has more than 20 years of industry experience in finance, business development and reservoir engineering with a focus on the Gulf Coast region. Included in his broad experience, Mr. Ebert has served in production engineering and reservoir engineering roles, among others, with Marathon Oil, Halliburton Energy Services and Bass Enterprises Production Company and as a member of the Energy Lending Group and Vice President of Hibernia National Bank. Mr. Ebert holds a degree in Petroleum Engineering from the University of Tulsa.

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.

Change in Executive Officers

On December 16, 2013, Michael Aldridge resigned as our Executive Vice President and Chief Financial Officer. In April 2014, Brian Daigle resigned as our Vice President Operations, effective April 30, 2014.

Directors

Our directors as of April 1, 2014, and their ages, principal occupations and business experience as of that date, were as follows:

Thomas F. Cooke. See biography above.

Andrew C. Clifford. See biography above.

Kevin M. Smith, age 69, has been the owner and principal of Kevin M. Smith, Inc., a geophysical consulting firm since 1984. Mr. Smith holds a B.S. in Geology and Geophysics from the University of Houston.

John W. Rhea, IV, age 61, is the owner and principal of J.W. Rhea & Associates, a petroleum exploration consulting firm, since 2009. Mr. Rhea served as a director, and in various executive positions including Chief Executive Officer, Chief Operating Officer and President, of Latitude Solutions, Inc., from July 2012 to November 2012. Latitude Solutions filed for protection under Chapter 7 of the U.S. Bankruptcy Code in November 2012. Mr. Rhea served as President, Chief Executive Officer and a Director, Gulf Energy Exploration Corp., a privately held oil and gas exploration and production company with principal operations in the Transition Zone offshore Texas, from 2006 to 2009. Mr. Rhea holds a B.S.M.E. in Engineering from the University of Texas.

Rex H. White, Jr., age 81, is owner and principal of Rex H. White, Jr., Attorney at Law, a Board Certified Oil, Gas and Mineral Law attorney. Previously, Mr. White worked as a petroleum geologist/geophysicist for approximately 10 years. Mr. White holds a B.S. in Geology, an M.A. in Geology with a minor in Petroleum Engineering and an L.L.B. all from the University of Texas.

Involvement in Certain Legal Proceedings

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

Compensation Committee Interlocks and Insider Participation

The current members of our compensation committee are Messrs. White, Rhea and Smith. In 2013, none of our executive officers served as a director or member of the compensation committee of another entity, where an executive officer of the entity served as one of our directors or on our compensation committee.

Board Independence

On the basis of information solicited from each director, our board has affirmatively determined that each of Messrs. Rhea, White and Smith has no material relationship with the company and is independent within the meaning of our corporate governance guidelines, which comply with the applicable NYSE MKT listing standards and SEC rules. In making this determination, the board, with assistance from the company s legal counsel, evaluated responses to a questionnaire completed annually by each director regarding relationships and possible conflicts of interest between each director, the company and management. In its review of director independence, the board considered all commercial, industrial, banking, consulting, legal, accounting, charitable, and familial relationships any director may have with the company or management.

EXECUTIVE COMPENSATION

Summary Executive Compensation Table

The table below summarizes the total compensation paid to or earned by our named executive officers for each of the two years ended December 31, 2013.

Name and Principal Position	Year	Salary	Bonus (1)	Stock Awards	Option Awards(2)	All Other Compensation(3)	Total
Thomas F. Cooke	2013	$ 311,100	$	$	$ 252,500	$ 45,927	$ 609,527
Chairman of the Board and Chief Executive Officer	2012	305,000	37,438			19,775	362,213
Andrew C. Clifford	2013	311,100			252,500	48,127	611,727
President	2012	305,000	37,438			33,373	375,811
Michael O. Aldridge (4)	2013	250,000				20,449	270,449
Executive Vice President and Chief Financial Officer	2012	250,000	24,550			10,000	284,550
Brian Daigle	2013	205,000				14,237	219,237
Vice President Operations	2012	187,500	18,658			7,503	213,661
Randal McDonald	2013	160,000				8,208	168,208
Controller	2012	160,000	11,784			6,400	178,184
John Ebert (5)	2013	74,173	10,000		150,300	2,850	237,323
VP Finance and Business Development	2012						

(1)

Bonuses include amounts attributable to a fiscal year even though paid after year end and, with respect to Mr. Ebert, a signing bonus on the start of employment.

(2)

The amounts reported in the Option Awards Column reflect the grant date fair value of the options granted to the named executive officers in the year reflected, determined using the Black-Scholes option model. For information relating to the assumptions made by us in valuing the option awards made to our named executive officers in fiscal year 2013, refer to Note 11 of our financial statements for the year ended December 31, 2013.

(3)

All other compensation consists of:

Name	Year	Travel Pay	Unused Vacation Pay	Auto Allowance	401k Plan Contribution
Thomas F. Cooke	2013	$ 19,800	$	$ 26,127	$
	2012			19,775	
Andrew C. Clifford	2013	13,000		24,927	10,200
	2012			17,167	16,206
Michael O. Aldridge	2013		10,790		9,659
	2012				10,000
Brian Daigle	2013		5,341		8,896
	2012				7,503
Randal McDonald	2013		1,285		6,923
	2012				6,400
John Ebert	2013				2,850

(4)

Mr. Aldridge resigned as our Executive Vice President and Chief Financial Officer on December 16, 2013.

(5)

Mr. Ebert commenced employment with Saratoga in August 2013 and was appointed Vice President Finance and Business Development in November 2013.

Narrative Discussion of Executive Compensation Table

Bonuses

In March 2012, the Compensation Committee adopted an Annual Incentive Plan pursuant to which the Committee, on an annual basis, establishes potential bonus payments for eligible employees based on performance criteria established each year by the Committee. During 2012 and 2013, the Committee adopted incentive programs and established performance based bonus criteria, in each year, based on growth in production, proven reserves and EBITDA.

Under the 2012 program, Saratoga partially satisfied the production growth criteria and paid bonuses, including the bonuses indicated in the tables above to the named executive officers, in each case representing approximately 12% of the maximum available bonuses under the program. Under the 2013 program, Saratoga partially satisfied the proven reserves growth criteria. However, the Committee exercised its discretion under the program and determined to pay no bonuses with respect to 2013 performance.

Employment Agreements

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

Outstanding Equity Awards at December 31, 2013

The following table includes certain information with respect to unexercised options held by named executive officers at December 31, 2013:

			Option Awards		
Name	**Grant Date**	**Number of Securities Underlying Unexercised Options Exercisable**	**Number of Securities Underlying Unexercised Options Unexercisable**	**Option Exercise Price**	**Option Expiration Date**

Thomas Cooke	06/10/13	62,500	187,500(1)	$ 3.00	06/09/18
Andrew Clifford	06/10/13	62,500	187,500(1)	3.00	06/09/18
Michael Aldridge(2)	10/31/11	100,000		4.585	03/16/14
Brian Daigle	07/01/10	40,000		1.53	07/01/20
	04/14/10	60,000		3.00	04/14/20
Randal McDonald	11/28/11	20,000	10,000(3)	4.62	11/28/18
John Ebert	08/12/13		90,000(3)	1.72	08/12/20

(1)

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

(2)

Information relates to options remaining exercisable after the termination of employment of Mr. Aldridge.

(3)

The stock options become exercisable in 1/3 annual increments on each of the first three anniversaries of the date of grant. The stock options will become immediately exercisable in their entirety in the event of certain changes in control.

Director Compensation

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

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

The table below summarizes the total compensation paid to or earned by our non-management directors during 2013. The amounts included in the Stock Awards and Option Awards columns reflect the aggregate grant date fair value, and do not necessarily equate to the income that will ultimately be realized by the director for these awards.

Name of Director	**Fees Earned or Paid in Cash**	**Stock Awards**	**Option Awards(1)**	**All Other Compensation**	**Total**
John W. Rhea, IV	$ 16,000	$	$ 58,100	$	$ 74,100
Kevin M. Smith	10,000		58,100		68,100
Rex H. White, Jr.	14,000		58,100		72,100

(1)

Amounts reflect the aggregate grant date fair value of the option awards (options). The Black-Scholes option model was used to determine the grant date fair value of the options that we granted to the directors. For information relating to the assumptions made by us in valuing the option awards made to our non-management directors in fiscal year 2013, refer to Note 11 of our financial statements for the year ended December 31, 2013.

As of December 31, 2013, each director had the following number of options outstanding: Mr. Rhea, 70,000; Mr. Smith, 155,000; and, Mr. White, 155,000.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Unless otherwise indicated, the table below shows the amount of our common stock beneficially owned as of April 24, 2014, by (1) each person known to beneficially own more than 5% of our outstanding common stock, (2) each of our directors and named executive officers, and (3) all directors and executive officers as a group.

Name of Beneficial Owner	Number of Shares Not Subject to Options	Number of Shares Subject to Exercisable Warrants and Options (1)	Total Number of Shares Beneficially Owned (1)	Percent of Class (1)(2)
Thomas F. Cooke	6,142,422(3)	125,000	6,267,422	20.2%
GSO Capital Partners (4)	4,800,000		4,800,000	15.5%
Macquarie Americas Corp. (5)	1,607,898		1,607,898	5.2%
Andrew C. Clifford	2,637,164(6)	125,000	2,762,164	8.9%
Brian Daigle	60,000	100,000	160,000	*
John W. Rhea, IV		70,000	70,000	*
Kevin M. Smith	195,473(7)	155,000	350,473	1.1%
Rex H. White, Jr.	52,500	155,000	207,500	*
Randal McDonald		20,000	20,000	*
John Ebert				
Directors and executive officers as a group (8 persons) (3) (6) (7)	9,087,559	750,000	9,837,559	