EVOLUTION PETROLEUM CORP
Form 10-K
September 12, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended June 30, 2014

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

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Nevada	41-1781991
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

2500 CityWest Blvd., Suite 1300, Houston, Texas 77042
(Address of principal executive offices and zip code)
(713) 935-0122
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	NYSE MKT
8.5% Series A Cumulative Preferred Stock, $0.001 par value	NYSE MKT

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

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

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

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

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

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

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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2013, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $12.34 on the NYSE MKT was $288,090,504.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 10, 2014, was 32,793,414.

DOCUMENTS INCORPORATED BY REFERENCE

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Portions of the proxy statement related to the registrant's 2014 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
2014 ANNUAL REPORT ON FORM 10-K
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This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words "plan," "expect," "project," "estimate," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in this Annual Report on Form 10-K as filed with the Securities and Exchange Commission. Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related

damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.
We use the terms, "EPM," "Company," "we," "us" and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

PART I

Item 1. Business

Note: See Glossary of Selected Petroleum Industry Terms at the back of this document - refer to Table of Contents

General

We are a petroleum company engaged primarily in the acquisition, exploitation and development of properties for the production of crude oil and natural gas, onshore in the United States. We acquire known crude oil and natural gas resources and exploit them through the application of conventional and specialized technology, with the objective of increasing production, ultimate recoveries, or both. In 2013, our business was modified to include a second focus on applying our proprietary artificial lift technology for recovering incremental oil and gas from existing wells. In this document, we provide additional information about our business operations and plans for commercializing our artificial lift technology, but it is not currently a separate reportable segment of our operations.

Our petroleum operations began in September of 2003. On May 26, 2004, our predecessor, Natural Gas Systems, Inc. (Delaware, "Old NGS"), a private corporation formed in September 2003, merged into a wholly-owned subsidiary of Reality Interactive, Inc. (Nevada, "Reality"), an inactive public company, which was renamed Natural Gas Systems, Inc. The former officers and directors of Reality resigned and the officers, directors and business operations of Old NGS became the Company. Concurrently with the listing of NGS shares on the NYSE MKT (formerly the American Stock Exchange) in July 2006, NGS was renamed Evolution Petroleum Corporation. Our principal executive offices are located at 2500 City West Blvd, Suite 1300, Houston, Texas 77042, and our telephone number is (713) 935-0122. We maintain a website at www.evolutionpetroleum.com, but information contained on our website does not constitute part of this document.

Our stock is traded on the NYSE MKT under the ticker symbol "EPM". We also have preferred stock which trades under the symbol "EPM.A"

At June 30, 2014, we had eight full-time employees, not including contract personnel and outsourced service providers. Our team is broadly experienced in oil and gas operations, development, acquisitions and financing. We follow a strategy of outsourcing most of our property accounting, human resources, administrative and non-core functions.

Business Strategy

Our business strategy is to acquire known, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology, including our patented artificial lift technology, to increase production, ultimate recoveries, or both. We also provide our artificial lift technology to other operators to improve recovery of long life, low decline production in otherwise mature wells.

Our principal assets include a CO_2 enhanced oil recovery project in Louisiana's Delhi Field and our patented artificial lift technology. We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain financial control of our assets for the benefit of our shareholders.

Delhi Field—Louisiana

Our mineral interests in the Holt Bryant Unit in the Delhi Field, located in Northeast Louisiana, are currently our most significant asset. The Unit has had a prolific production history totaling approximately 190 million bbls of oil through primary and partial secondary recovery operations since its discovery in the mid-1940s. At the time of our $2.8 million purchase in 2003, the Unit had minimal production.

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The Unit is currently producing as an EOR project utilizing CO2 flood technology following the sale of a majority of our interests to a subsidiary of Denbury Resources, Inc., the current operator, in 2006.

We own two types of interests in the Unit:

- 7.4% of overriding and mineral royalty interests that are in effect throughout the life of the project, free of all operating and capital cost burdens.
- A 23.9% reversionary working interest with an associated 19.1% net revenue interest. The working interest reverts to us when the operator has generated $200 million of net revenue from the 100% working interest less direct operating expenses and the cost of purchased CO2. Upon reversion of the deemed payout, regardless of the operator's actual capital expenditures, we will begin bearing 23.9% of all future operating and capital expense and our net revenue interest will increase from 7.4% to an aggregate 26.5%. Our current independent reserves report dated June 30, 2014 assumes the deemed payout to occur during the fourth calendar quarter of 2014, based on information from and statements by the operator.

Our independent reservoir engineers, DeGolyer & MacNaughton, assigned the following estimated reserves net to our interests at Delhi as of June 30, 2014:

- 13.1 million bbls of proved oil equivalent reserves, with a PV-10* of $318.1 million
- 9.5 million bbls of probable** oil equivalent reserves, with a PV-10* of $135.9 million
- 3.0 million bbls of possible** oil equivalent reserves, with a PV-10* of $20.1 million

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* PV-10 of Proved reserves is a non-GAAP measure, reconciled to the Standardized Measure at "Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues" under Item 2. Properties of this Form 10-K. Probable and Possible reserves are not recognized by GAAP, and therefore the PV-10 of such reserves cannot be reconciled to a GAAP measure.

** With respect to the above reserve numbers, estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

The operator has planned multiple phases for the installation of the CO2 flood.

Phase I began CO2 injection in November 2009. First oil production response occurred in March 2010, about three to four months earlier than expected, and production in the field increased to approximately 2,000 gross BO per day.

Implementation of Phase II, which was more than double the size of Phase I, commenced with incremental CO2 injection at the end of December 2010. First oil production response from Phase II occurred during March 2011, three or more months ahead of expectations, and field gross production increased to more than 4,000 BO per day.

Phase III was installed during calendar 2011, and was expanded twice during calendar 2011. Production subsequently increased to more than 6,000 BO per day.

Phase IV was substantially installed during the first six months of calendar 2012. Gross field production increased to more than 7,500 BO per day before the operator temporarily suspended CO2 injection in a portion of the field due to the June 2013 fluid release event described in Item 7. "Management's Discussion and Analysis".

During early calendar 2013, the operator intensified development in the previously redeveloped western side of the field based on production results and new geological mapping that included the results of seismic data acquired over the last few years. During June 2013, a well fluids release occurred at Delhi which resulted in a temporary decline in production from 7,500 BBls/day to approximately 5,700 BBls per day and an attendant near term decrease in revenue from our royalty interests in the Delhi field. The operator has taken the position that these costs can be charged to our payout account and accordingly, this action has delayed our expected working interest reversion by approximately a year. We dispute the operator's position on the treatment of these costs and have filed suit against the operator over this matter and other issues related to the original 2006 agreements.

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Since the June 2013 fluids release, the operator has delayed further development of the field and has stated its intent not to resume significant capital spending until after reversion of our working interest has occurred. We expect that development activities will resume after reversion and that two of the three remaining phases will be installed over the next few years in the eastern part of the field. A third previously planned phase, part of which lies under the town of Delhi (population approximately 3,000), is being re-evaluated by the operator. The reserves in this phase have been reclassified from proved to probable. We further expect that probable reserves associated with three smaller reservoirs within the Unit in similar formations with similar production history will be developed as an additional phase of the EOR project early in the next decade.

During fiscal 2014, we realized an average price of $102.96 per BBL based on Delhi's Louisiana Light Sweet ("LLS") crude oil pricing, a 4% premium over the $99.25 per BBL sales price we received from our Texas production. This positive LLS price differential has narrowed significantly from past years and we do not currently expect a large positive market price differential for LLS going forward.

Artificial Lift Technology (GARP®)

Our artificial lift technology registered as GARP® (Gas Assisted Rod Pump) was developed internally by one of our officers. Its design is intended to extend the life of horizontal and vertical wells with gas, oil or associated water production with the expectation of recovering an additional 10-30% of cumulative recovery at a cost of less than $10 per BOE. We received a patent on our GARP® technology on August 30, 2011, which provides U.S. patent protection for the technology through early 2028. We have further filed for a continuation in part to our patent for recent improvements in the technology.

Prior to patent issuance, we tested the GARP® technology on certain marginal producers we owned and operated in the Giddings Field. The tests were successful in demonstrating that the process works; however, these candidates were unable to prove commercial viability due to their low primary recoveries as producers.

Subsequent to receiving our patent, we entered into demonstration JV projects with two different industry operators during fiscal 2012 to prove commercial application. We further expanded our commercial tests during fiscal 2013 with two additional installations and a third in fiscal 2014. All five of these installations were successful in re-establishing commercial production. One well subsequently ceased oil production when an offset well was hydraulically fractured and the water migrated to our well bore. During fiscal 2014, we entered into a commercial agreement to install our technology on at least five wells in the Giddings Field. Three installations were completed as of the end of fiscal 2014, all three of which were successful in increasing production. One of the three installations is being terminated and our technology removed for installation in another well due to an obstruction in the well bore that prevented economic production. A fourth attempted installation was halted early in the installation process due also to an undisclosed obstruction.

We are in discussions with multiple industry operators to further expand the business to other fields during fiscal 2015. With continued success and industry acceptance, we believe GARP® could be applicable to a large number of late stage horizontal and vertical wells worldwide.

Based on the significant amount of production history, DeGolyer & MacNaughton assigned proved reserves of 172 MBOE to three GARP® installations that we operate with PV-10 of $1.7 million. Recent installations during fiscal 2014 do not yet have sufficient history to estimate expected future performance. Our fees, though based on a percentage of net profits from the wells, will not generally result in the assignment of reserves by our petroleum engineers.

Other Projects

Giddings Field—Central Texas

We began leasing activities in the Giddings Field in December 2006. In late calendar 2007, we initiated a redevelopment drilling program in the Giddings Field targeting the Austin Chalk and Georgetown formations. During fiscal 2013, we began and completed a series of transactions that monetized all of our non-GARP® producing wells and drilling locations.

We retained a 3-5% overriding royalty interest on 2,094 acres on all depths below the base of the Austin Chalk in Brazos, Burleson and Fayette Counties, Texas. We also retained overriding royalty interests of approximately 5% in 900 net acres in the Woodbine formation and a 15% back-in working interest on approximately 258 net acres in Grimes County, Texas. We do not expect to assign any reserves to these residual interests until such time as there are successful drilling results.

Lopez Field—South Texas

We acquired leases covering approximately 782 net acres in the Lopez Field in South Texas as a first effort to test the concept of redeveloping old oil fields utilizing high flow rate production. While our development activity in the Lopez Field confirmed our concept and the potential for developing material oil reserves, the time and effort required to achieve reserves has lowered the attractiveness of the potential. Consequently, we elected to monetize this asset during fiscal 2013 and completed such monetization in fiscal 2014.

Mississippi Lime—Kay County, Oklahoma

In 2012, we acquired a 45% interest in a joint venture with Orion Exploration, a private company based in Tulsa, OK. The joint venture is operated by Orion and engaged in the horizontal development of the Mississippi Lime reservoir in Kay County, Oklahoma. Our leasehold position is located in the eastern, more oil-prone side of the play. With the objective reservoir less than 4,000 feet in depth, the cost of drilling, fracturing and completing a horizontal well with 4,000 feet of lateral length was estimated to be $3.2 million. The joint venture currently holds approximately 6,600 acres of undeveloped leasehold. To date, we have drilled one gross salt water disposal well and reached total depth on two horizontally drilled wells in the Mississippi Lime formation, the Sneath #1-24 and the Hendrickson #1-1. While both wells produced at the fluid rates expected, the quantities of oil and gas were far less than expected. We subsequently reworked both wells to test the role of structure in production, and have since determined that this play is a structural play requiring substantial geophysical and geological work and expertise in order to be successful, as opposed to a resource play in which engineering is the primary requirement. Since such business is not within our current strategy, we elected in fiscal 2013 to reduce our joint venture interest in undeveloped leases to 33.9%, resulting in a $1.2 million reduction in both our net property and accounts payable. We currently plan to divest of our remaining assets in this venture. Based on our drilling results and divestiture plans, we are no longer carrying any probable reserves for this asset.

Markets and Customers

We market our production to third parties in a manner consistent with industry practices. In the U.S. market where we operate, crude oil and natural gas liquids are readily transportable and marketable. We do not currently market our share of crude oil production from Delhi. Although we have the right to take our current interests in-kind, we are currently accepting terms under the Delhi operator's agreement with Plains Marketing LP for the delivery and pricing of our oil there. The oil from Delhi is currently transported from the field by pipeline, which results in better net pricing than the alternative of transportation by truck.

In January of 2008, we began selling crude oil from our Giddings properties (which includes our GARP® wells) to Enterprise Crude Oil LLC, a crude oil gathering, transportation, storage and marketing company. Our agreements with Enterprise Crude Oil LLC are under a normal "evergreen" sales contracts with a thirty day cancellation provision. In June 2014, we began selling crude oil from our Giddings properties to Sunoco Partners. Oil production from our Lopez Field was sold to Flint Hill Resources. We believe that other crude oil purchasers are readily available.

We sell our natural gas and natural gas liquids from our properties in the Giddings Field under the terms of normal evergreen sales contracts at competitive prices with DCP Midstream, LP, and ETC Texas Pipeline, LTD. Gas sold to DCP and ETC is processed for removal of natural gas liquids, and we receive the proceeds from the sale of the NGL products less a fee and certain operating expenses. We have no other business relationships with our crude oil, natural gas or natural gas liquids purchasers.

The following table sets forth purchasers of our oil and natural gas production for the years indicated:

	Year Ended June 30,					
Customer	2014		2013		2012	
Plains Marketing LP (includes Delhi production)	96	%	90	%	84	%
Enterprise Crude Oil LLC	2	%	4	%	7	%
Flint Hills Resources	1	%	2	%	1	%
ETC Texas Pipeline, Ltd.	1	%	—	%	3	%
All others	—	%	4	%	5	%
Total	100	%	100	%	100	%

The loss of any single purchaser (which we believe could readily be replaced) would not be expected to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition in the market for our oil and natural gas production, which in turn could negatively impact the prices we receive. Additionally, if Delhi production were unable to be transported from the field by pipeline, our pricing and potentially our near term production levels could be adversely affected.

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Market Conditions

Marketing of crude oil, natural gas, and natural gas liquids is influenced by many factors that are beyond our control, the exact effect of which is difficult to predict. These factors include changes in supply and demand, market prices, government regulation and actions of major foreign producers.

Over the past 25 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than $10 to in excess of $140 per barrel. Worldwide factors such as geopolitical, macroeconomic, supply and demand, refining capacity, petrochemical production and derivatives trading, among others, influence prices for crude oil. Local factors also influence prices for crude oil and include increasing or decreasing production trends, quality differences, regulation and transportation issues unique to certain producing regions and reservoirs. In particular, the price we received for our Delhi oil materially exceeded the price we received for our Texas oil production beginning in the second half of fiscal 2011. This positive price differential narrowed significantly during the past year and we do not currently expect a large positive price differential going forward.

Also over the past 25 years, domestic natural gas prices have been extremely volatile, ranging from $1 to $15 per MMBTU. The spot market for natural gas, changes in supply and demand, derivatives trading, pipeline availability, BTU content of the natural gas and weather patterns, among others, cause natural gas prices to be subject to significant fluctuations. Due to the practical difficulties in transporting natural gas, local and regional factors tend to influence product prices more for natural gas than for crude oil.

Competition

The oil and natural gas industry is highly competitive for prospects, acreage and capital. Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. Competitors are national, regional or local in scope and compete on the basis of financial resources, technical prowess or local knowledge. The principal competitive factors in our industry are expertise in given geographical and geological areas and the abilities to efficiently conduct operations, achieve technological advantages, identify and acquire economically producible reserves and obtain affordable capital.

Government Regulation

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. To the best of our knowledge, we are in compliance with all laws and regulations applicable to our operations and we believe that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements which are unpredictable. However, we do not currently anticipate that future compliance with existing laws and regulations will have a materially adverse effect on our consolidated financial position or results of operations.

See "Government regulation and liability for environmental matters that may adversely affect our business and results of operations" under Item 1A. Risk Factors of this Form 10-K, for additional information regarding government regulation.

Insurance

We maintain insurance on our operated properties and operations for risks and in amounts customary in the industry. Such insurance includes general liability, excess liability, control of well, operators extra expense, casualty, fraud and directors & officer's liability coverage. Not all losses are insured, and we retain certain risks of loss through deductibles, limits and self-retentions. Furthermore, we are unable to insure against risks associated with our reversionary working interest until such reversion occurs. We do not carry lost profits coverage and we do not have coverage for consequential damages.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports with the SEC. Our reports filed with the SEC are available free of charge to the general public through our website at www.evolutionpetroleum.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 2500 City West Blvd, Suite 1300, Houston, Texas 77042, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a

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website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors

Risks relating to the Company

Our revenues are concentrated in one asset and declines in production or other events beyond our control could have a material adverse effect on our results of operations.

Over 95% of our revenues come from our royalty interests in the Delhi field in Louisiana and our future revenues will be further concentrated in that field upon reversion of our working interest there, currently expected to occur during the fourth quarter of calendar year 2014. Any significant downturn in production, oil and gas prices, or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations. We are not the operator of the Delhi property, and our revenues and future growth are heavily dependent on the success of operations which we do not control. In June 2013, a fluids release from one or more previously plugged wells occurred at the Delhi field that resulted in a significant temporary downturn in the daily oil production at the Delhi field, which has impacted the revenues received from our royalty interest and has delayed the reversion date of our working interest. In addition, the event has prompted the operator to pursue a more conservative development plan for the balance of the field that projects a lower peak production rate occurring at a later date, offset by a lower rate of decline.

Operating results from oil and natural gas production may decline; we may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline. In the near term, our production is heavily dependent on our 7.4% of royalty interests and the pending reversion to us of a 23.9% working interest in EOR production that began during March 2010 in the Delhi Field. In addition, our production will be impacted by the results of wells in which we have installed our GARP® technology and any future installations in which we are compensated with production or its equivalent. Although EOR production from proved reserves at Delhi has and is expected to grow over time and we expect to grow the number of GARP® installations, environmental or operating problems or lack of future investment at Delhi, lack of success in adding GARP® installations or a change in our GARP® compensation model without further development activities in new or existing projects or without acquisitions of producing properties, our net production of oil and natural gas could decline significantly over time, which could have a material adverse effect on our financial condition.

We have limited control over the activities on properties we do not operate.

Some of our properties, including our Delhi interests, are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Operators of these properties may act in ways that are not in our best interest. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production and materially and adversely affect our financial conditions and results of operations.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted reservoirs, naturally fractured or low permeability reservoirs, or relatively shallow reservoirs. Shallower reservoirs usually have lower pressure, which translates into fewer natural gas volumes in place. Low permeability reservoirs require more wells and substantial stimulation for development of commercial production. Naturally fractured reservoirs require penetration of sufficient undepleted fractures to establish commercial production. Depleted reservoirs require successful application of newer technology to unlock incremental reserves.

Our CO2-EOR project in the Delhi Field, operated by a subsidiary of Denbury Resources Inc., requires significant amounts of CO2 reserves, development capital and technical expertise, the sources of which to date have been committed by the operator. Although initial CO2 injection began at Delhi in November 2009, initial oil production response began in March 2010 and a large part of the capital budget has already been expended, substantial capital remains to be invested to fully develop the EOR project and further increase production. The operator's failure to manage these and other technical, environmental, operating, strategic, financial and logistical risks may cause ultimate enhanced recoveries from the planned

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CO2-EOR project to fall short of our expectations in volume and/or timing. Such occurrences would have a material adverse effect on the Company and its results of operations.

The existing well bores in which we are installing GARP® were originally drilled years or decades earlier. As such, they contain older casing or debris that could be more subject to failure, or the well files, if available, may be incomplete or incorrect. Such problems can result in the complete loss of a well or much higher costs. Expected results are based on theoretical estimates using historical data, which may not be complete or accurate, and thus such estimates may not prove accurate. Terms of compensation for installing GARP® may well change over time based on results achieved, industry acceptance, marketing efforts and other factors.

Our projects generally require that we acquire new leases in and around established fields or other known resources, and drill and complete wells, some of which may be horizontal, as well as negotiate the purchase of existing well bores and production equipment or install our proprietary artificial lift technology that has yet to be universally proven. Leases may not be available and required oil field services may not be obtainable on the desired schedule or at the expected costs. While the projected drilling results may be considered to be low to moderate in risk, there is no assurance as to what productive results may be obtained, if any.

Crude oil and natural gas development, re-completion of wells from one reservoir to another reservoir, restoring wells to production and drilling and completing new wells are speculative activities and involve numerous risks and substantial uncertain costs.

Our growth will be materially dependent upon the success of our future development program. Drilling for crude oil and natural gas and re-working existing wells involve numerous risks, including the risk that no commercially productive crude oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in formations;
- equipment failures or accidents;
- environmental events;
- inability to obtain or maintain leases on economic terms, where applicable;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as hydraulic fracturing, horizontal drilling or CO2 injection or other injectants do not guarantee that we will find and produce crude oil and/or natural gas in our wells in economic quantities. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline.

We may also identify and develop prospects through a number of methods, some of which do not include horizontal drilling, hydraulic fracturing or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. We cannot assure you that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive crude oil or natural gas.

The loss of a large single purchaser of our oil and natural gas could reduce the competition of our production.

For the year ended June 30, 2014, seven purchasers accounted for all of our oil and natural gas revenues, with one purchaser accounting for over 95% of our sales. The loss of a large single purchaser for our oil and natural gas production could negatively impact the revenue we receive.

Our patented GARP® technology may not achieve acceptance or widespread adoption by industry.

We have developed, field tested and initiated commercialization of our artificial lift technology, GARP® (Gas Assisted Rod Pump), though it may not generate substantial value. Our further success in commercializing the technology will depend upon additional positive field tests, additional customers, acceptance by industry and our ability to defend the technology from competitors through confidentiality, trade secret and patent protection.

We may be unable to continue licensing from third parties the technologies that we use in our business operations.

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As is customary in the crude oil and natural gas industry, we utilize a variety of widely available technologies in the crude oil and natural gas development and drilling process. We do not have any patents or copyrights for the technology we currently utilize, except for the registered trademark and issued patent on our GARP® artificial lift technology that is in the process of commercialization. We generally license or purchase services from the holders of such technology, or outsource the technology integral to our business from third parties. Our commercial success will depend in part on these sources of technology and assumes that such sources will not infringe on the proprietary rights of others. We cannot be certain whether any third-party patents will require us to utilize or develop alternative technology or to alter our business plan, obtain additional licenses, or cease activities that infringe on third-parties' intellectual property rights. Our inability to acquire any third-party licenses, or to integrate the related third-party products into our business plan, could result in delays in development unless and until equivalent products can be identified, licensed, and integrated. Existing or future licenses may not continue to be available to us on commercially reasonable terms or at all. Litigation, which could result in substantial cost to us, may be necessary to enforce any patents licensed to us or to determine the scope and validity of third-party obligations or to protect our patent rights on GARP®.

Our crude oil and natural gas reserves are only estimates and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their estimated values. Our reserves are only estimates that may prove to be inaccurate because of these uncertainties. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves depend upon a number of variable factors, such as historical production from the area compared with production from other producing areas and assumptions concerning effects of regulations by governmental agencies, future crude oil and natural gas product prices, future operating costs, severance and excise taxes, development costs and work-over and remedial costs. Some or all of these assumptions may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from prepared by different engineers or by the same engineers but at different times, may vary substantially.

Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the crude oil and natural gas industry in general. PV-10 does not necessarily correspond to market value.

Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.

We review on a periodic basis the carrying value of our crude oil and natural gas properties under the applicable rules of the various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this "ceiling" test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our crude oil and natural gas properties when crude oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices for crude oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities.

Crude oil and natural gas prices are highly volatile in general and low prices will negatively affect our financial results.

Our revenues, operating results, profitability, cash flow, future rate of growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of crude oil and natural gas. Lower crude oil and natural gas prices also may reduce the amount of crude oil and natural gas that we can produce economically. Historically, the markets for crude oil and natural gas have been very volatile, and such markets are likely to continue to be volatile in the future. Prices for crude oil and natural gas are subject to wide fluctuation in response to

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relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of crude oil, natural gas and NGLs;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political instability or armed conflict in oil-producing regions;
- the price and level of foreign imports; and
- overall domestic and global economic conditions.

It is extremely difficult to predict future crude oil and natural gas price movements with any certainty. Declines in crude oil and natural gas prices may materially adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Further, crude oil and natural gas prices do not move in tandem. Because approximately 79% of our proved reserves at June 30, 2014 are crude oil reserves and 17% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas prices may adversely affect our financial position.

We may have difficulty managing future growth and the related demands on our resources and may have difficulty in achieving future growth.

Although we hope to experience growth through acquisitions and development activity, any such growth may place a significant strain on our financial, technical, operational and administrative resources. Our ability to grow will depend upon a number of factors, including:

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;
- hydrocarbon prices;
- drilling, completion and equipment prices;
- our ability to successfully integrate new properties;
- our access to capital; and
- the Delhi Field operator's ability to: (i) deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome, secure all of the development capital necessary to fund its and our cost interests and (ii) to successfully manage technical, operating, environmental, strategic and logistical development and operating risks, among other things.

We cannot assure you that we will be able to successfully grow or manage any such growth.

Our operations require significant amounts of capital and additional financing may be necessary in order for us to continue our exploration activities, including meeting potential future drilling obligations.

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisitions, exploitation and development activities. Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production is established. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our current production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available to us on favorable terms.

Government regulation and liability for environmental matters may adversely affect our business and results of operations.

Crude oil and natural gas operations are subject to extensive federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. There are federal, state and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation and disposal of crude oil and natural gas, by-products thereof and other substances and materials produced or used in connection with crude oil and natural gas operations. In addition, we may inherit liability for environmental damages, whether actual or not, caused by previous owners of property we purchase or lease or nearby properties. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us, such as diminishing the demand for our products through legislative enactment of proposed new penalties, fines and/or taxes on carbon that could have the effect of raising prices to the end user.

For example, currently proposed federal legislation, that, if adopted, could adversely affect our business, financial condition and results of operations, includes the following:

- Taxes. President Obama's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted , make significant changes to U.S. tax laws. These changes include, but are not limited to (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for certain domestic production activities, (iii) an extension of the amortization period for certain geological and geophysical expenditures, and (iv) the repeal of the percentage depletion allowance for oil and natural gas properties; and
- Hydraulic Fracturing. The U.S. Congress, the EPA and various states are currently considering legislation that could adversely affect the use of the hydraulic-fracturing process. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. Any proposed legislation, if adopted, could establish an additional level of regulation, permitting and restrictions at the federal level that could adversely affect the development of unconventional oil and natural gas resources.

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

The crude oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, hurricanes, flooding, pollution, releases of toxic gas and other environmental hazards and risks, which can result in (i) damage to or destruction of wells and/or production facilities, (ii) damage to or destruction of formations, (iii) injury to persons, (iv) loss of life, or (v) damage to property, the environment or natural resources. While we carry general liability, control of well, and operator's extra expense coverage typical in our industry, we are not fully insured against all risks incident to our business. Environmental events similar to that experienced in the Delhi Field in June 2013 could defer revenue, postpone the payout of our reversionary working interest or increase operating costs and maintenance capital expenditures. Due to their characteristics, we have been unable to insure our reversionary working interest and royalty interests against operating risks of the type experienced in June 2013.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers, the loss of any of whom could have a material adverse effect on our operations. In particular, our future success is dependent upon Robert S. Herlin, our Chairman and Chief Executive Officer, Randall D. Keys, our President, Chief Financial Officer and Treasurer, and Daryl V. Mazzanti, our Vice President of Operations, for sourcing, evaluating and closing deals, capital raising, and oversight of development and operations. Presently, the Company is not a beneficiary of any key man insurance.

Oil field service and materials' prices may increase, and the availability of such services and materials may be inadequate to meet our needs.

Our business plan to develop or redevelop crude oil and natural gas resources requires third party oilfield service vendors and various material providers, which we do not control. We also rely on third-party carriers for the transportation and distribution of our production. As our production increases, so does our need for such services and materials. Generally, we do not have long-term agreements with our service and materials providers. Accordingly, there is a risk that any of our service providers could discontinue servicing our crude oil and natural gas fields for any reason or we may not be able to source the materials we need. Any delay in locating, establishing relationships, and training our sources could result in production shortages and maintenance problems, with a resulting loss of revenue to us. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelop plans.

We cannot market the crude oil and natural gas that we produce without the assistance of third parties.

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The marketability of the crude oil and natural gas that we produce depends upon the proximity of our reserves to, and the capacity of, facilities and third-party services, including crude oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities necessary to make the products marketable for end use. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in or delay or discontinuance could adversely affect our financial condition.

We face strong competition from larger oil and gas companies.

Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. We may not be able to successfully conduct our operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment. Specifically, these larger competitors may be able to pay more for development projects and productive crude oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may be able to expend greater resources on hiring contract service providers, obtaining oilfield equipment and acquiring the existing and changing technologies that we believe are and will be increasingly important to attaining success in our industry.

We are, and in the future may become, involved in legal proceedings related to our Delhi interest or other properties or operations and, as a result, may incur substantial costs in connection with those proceedings.

On August 23, 2012, we, and our wholly owned subsidiary NGS Sub Corp and Robert S. Herlin, our President, were served with a lawsuit filed in federal court by James H. and Kristy S. Jones. The plaintiffs allege primarily that the defendants wrongfully purchased the plaintiffs' 0.048119 overriding royalty interest in the Delhi Unit in January 2006 by failing to divulge the existence of an alleged previous agreement to develop the Delhi Field for EOR. Although we believe that the claims are without merit and not timely, and intend to vigorously defend against the claims, an adverse resolution of this proceeding could subject us to significant monetary damages and other penalties, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

In December 2013 we filed a lawsuit against the operator of the Delhi Field alleging that the operator improperly charged the payout account for capital expenditures and costs of capital, failed to adhere to preferential rights to participate in acquisitions within the defined area of mutual interest, breached the promises to assume environmental liabilities and fully indemnify us from such costs, and other breaches. We are seeking declaration of the validity of the 2006 agreements and recovery of damages and attorneys' fees. The operator subsequently filed counterclaims, including the assertion that we owed it additional revenue interests pursuant to the 2006 agreements and that the transfer of our reversionary working interest from our wholly owned subsidiary to our parent corporation and subsequently to another wholly owned subsidiary breached their preferential right to purchase. We have denied their counterclaims as being without merit and not timely. We may incur significant legal costs in this matter and the outcome is uncertain.

Ownership of our oil, gas and mineral production depends on good title to our property.

Good and clear title to our oil, gas and mineral properties is important to our business. Although title reviews will generally be conducted prior to the purchase of most oil, gas and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction or elimination of the revenue received by us from such properties.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic recovery in the United States or abroad remains prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Risks Associated with Our Stock

Our stock price has been and may continue to be volatile.

Our common stock is relatively thinly traded and the market price has been, and is likely to continue to be, volatile.
For example, during the year prior to June 30, 2014, our stock price as traded on the NYSE MKT ranged from $13.83 to $9.92. The variance in our stock price makes it difficult to forecast with any certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;
- changes or fluctuations in the commodity prices of crude oil and natural gas;
- general conditions and trends in the crude oil and natural gas industry;
- redemption demands on institutional funds that hold our stock; and
- general economic, political and market conditions.

Our executive officers, directors and affiliates may be able to control the election of our directors and all other matters submitted to our stockholders for approval.

Our executive officers and directors, in the aggregate, beneficially own approximately 3.1 million shares, or approximately 10% of our beneficial common stock base. JVL Advisors LLC controls approximately 5.0 million shares or approximately 15% of our outstanding common stock. As a result, these holders could exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

The market for our common stock is limited and may not provide adequate liquidity.

Our common stock is relatively thinly traded on the NYSE MKT. In the year prior to June 30, 2014, the actual daily trading volume in our common stock ranged from 12,700 shares of common stock to a high of 2,254,100 shares of common stock traded. On most days, this trading volume means there is limited liquidity in our shares of common stock. Selling our shares is more difficult because smaller quantities of shares are bought and sold and news media coverage about us is limited. These factors result in a limited trading market for our common stock and therefore holders of our stock may be unable to sell shares purchased, should they desire to do so.

If securities or industry analyst do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. To our knowledge there are four independent analysts that cover our company. The limited number of published reports by independent securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price could decline. If any analyst ceases coverage of our company or fails to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price to decline.

The issuance of additional common stock and preferred stock could dilute existing stockholders.

We currently have in place a registration statement which allows the Company to publicly issue up to $500 million of additional securities, including debt, common stock, preferred stock, and warrants. At any time we may make private offerings of our securities. The shelf registration is intended to provide greater flexibility to the company in financing growth or changing our capital structure. We are authorized to issue up to 100,000,000 shares of common stock. To the extent of such authorization, our board of directors has the ability, without seeking stockholder approval, to issue additional shares of common stock in the future for such consideration as our board may consider sufficient. The issuance of additional common stock in the future would reduce the proportionate ownership and voting power of the common stock now outstanding. We are also authorized to issue up to 5,000,000 shares of preferred stock , the rights and preferences of which may be designated in series by our board of directors, of which, at least 317,319 shares of

Series A Preferred Stock are issued and outstanding as of September 10, 2014. Such designation of new series of preferred stock may be made without stockholder approval, and could create additional securities which would have dividend and liquidation preferences over the common stock now outstanding. Preferred stockholders could adversely affect the rights of holders of common stock by:

- exercising voting, redemption and conversion rights to the detriment of the holders of common stock;

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- receiving preferences over the holders of common stock regarding our surplus funds in the event of our dissolution, liquidation or the payment of dividends to Preferred stockholders;
- delaying, deferring or preventing a change in control of our company; and
- discouraging bids for our common stock.

Our Series A Preferred Stock is thinly traded and has no stated maturity date.

The shares of Series A Preferred Stock were listed for trading on the NYSE MKT under the symbol "EPM.PR.A" on July 5, 2011 and are thinly traded on the NYSE MKT. Since the securities have no stated maturity date, investors seeking liquidity will be limited to selling their shares in the secondary market. An active trading market for the shares may not develop or, even if it develops, may not last, in which case the trading price of the shares could be adversely affected and your ability to transfer your shares of Series A Preferred Stock will be limited. We have the right to redeem all shares of Series A Preferred Stock at face value at any time.

The market value of our Series A Preferred Stock could be adversely affected by various factors.

The trading price of the shares of Series A Preferred Stock may depend on many factors, including:

- market liquidity;
- prevailing interest rates;
- optional redemption by us;
- the market for similar securities;
- general economic conditions; and
- our financial condition, performance and prospects.

For example, higher market interest rates could cause the market price of the Series A Preferred Stock to decrease.

We could be prevented from paying dividends on our Series A Preferred Stock.

Although dividends on the Series A Preferred Stock are cumulative and arrearages will accrue until paid, preferred stockholders will only receive cash dividends on the Series A Preferred Stock if we have funds legally available for the payment of dividends and such payment is not restricted or prohibited by law, the terms of any senior shares or any documents governing our indebtedness. Our business may not generate sufficient cash flow from operations to enable us to pay dividends on the Series A Preferred Stock when payable. In addition, existing or future debt, credit facility arrangements, contractual covenants or arrangements we enter into may restrict or prevent future dividend payments. Accordingly, there is no guarantee that we will be able to pay any cash dividends on our Series A Preferred Stock.

Furthermore, in some circumstances, we may pay dividends in stock rather than cash, and our stock price may be depressed at such time.

Our Series A Preferred Stock has not been rated and will be subordinated to all of our existing and future debt.

Our Series A Preferred Stock has not been rated by any nationally recognized statistical rating organization. In addition, with respect to dividend rights and rights upon our liquidation, winding-up or dissolution, the Series A Preferred Stock will be subordinated to any existing and future debt and all future capital stock designated as senior to the Series A Preferred Stock. We may also incur additional indebtedness in the future to finance potential acquisitions or the development of new properties and the terms of the Series A Preferred Stock do not require us to obtain the approval of the holders of the Series A Preferred Stock prior to incurring additional indebtedness. As a result, our existing and future indebtedness may be subject to restrictive covenants or other provisions that may prevent or otherwise limit our ability to make dividend or liquidation payments on our Series A Preferred Stock. Upon our liquidation, our obligations to our creditors would rank senior to our Series A Preferred Stock and would be required to be paid before any payments could be made to holders of our Series A Preferred Stock.

We could be prevented from continuing to pay dividends on our Common Stock.

Our board of directors declared dividends on our common stock for the first time in November 2013 and we have paid a total of three quarterly cash dividends on our common stock. However, there is no certainty that dividends will be declared by the board of directors in the future. Any payment of cash dividends on our common stock in the future will be dependent upon the amount of funds legally available, our earnings, if any, our financial condition and business plan, restrictions contained in our Series A preferred stock and any debt instruments, contractual covenants or arrangements we may enter into, our anticipated capital requirements and other factors that our board of directors may think are relevant. Accordingly, there is no guarantee that we will be able to continue to pay any cash dividends on our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Company Location

Our corporate headquarters are located at 2500 CityWest Boulevard, Suite 1300, Houston, Texas. We entered into a sublease agreement, effective on March 1, 2007, to rent approximately 8,400 square feet of Class "A" office space in the Westchase District area in West Houston. The current monthly base rent is $13,251, having escalated from a monthly base rate of $11,507 in August 2011. The sublease expires by its term on July 1, 2016.

Oil & Gas Properties

Additional detailed information describing the types of properties we own can be found in "Business Strategy" under Item 1. Business of this Form 10-K.

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The SEC sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Subject to limited exceptions, the rules also require that 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.

There are numerous uncertainties inherent in estimating quantities of proved reserves and estimates of reserves quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Estimated future net revenues discounted at 10% or PV-10 is a financial measure that is not recognized by GAAP. We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies, and that it is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, analysts and investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it 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 as defined under GAAP, and reconciled herein.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2014

Our proved and probable reserves at June 30, 2014, denominated in equivalent barrels using six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineer, DeGolyer and MacNaughton ("D&M"). D&M was selected for our interests in the Delhi Field due to their expertise in CO_2-EOR projects and to ensure consistency with the operator who has utilized D&M for their reserves estimates in the Delhi Field. We also chose to have D&M estimate our Giddings properties in 2014 in order to simplify and consolidate our reserve reporting. D&M has significant expertise in this region as well. The scope and results of their procedures are summarized in a letter from the firm, which is included as exhibit 99.4 to this Annual Report on Form 10-K.

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The following table sets forth our estimated proved and probable reserves as of June 30, 2014. See Note 18 to the consolidated financial statements, where additional unaudited reserve information is provided. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $100.37 per barrel of crude oil and $4.10 per MMbtu of natural gas. The price of natural gas liquids was based on the historical price received, if no historical received price is available, historical pricing in the area. Pricing differentials were applied to all properties, on an individual property basis. Quality adjustments have been applied based on actual BTU factors for each well and a shrinkage factor has been applied based on production volumes versus actual sales volumes.

June 30, 2014

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)	PV-10
PROVED					
Developed (60% of Proved)	7,858	32	481	7,970	$257,954,613
Undeveloped (40% of Proved)	2,668	2,247	2,426	5,319	61,790,784
TOTAL PROVED	10,526	2,279	2,907	13,289	$319,745,397
Product Mix	79 %	17 %	4 %	100 %	
PROBABLE					
Developed (43% of Probable)	4,039	—	—	4,039	$79,823,271
Undeveloped (57% of Probable)	3,381	1,735	1,873	5,428	56,106,975
TOTAL PROBABLE	7,420	1,735	1,873	9,467	$135,930,246
Product Mix	79 %	18 %	3 %	100 %	

The following tables present a reconciliation of changes in our proved and probable reserves by major property, on the basis of equivalent MBOE quantities.

Reconciliation of Changes in Proved Reserves by Major Property

Proved reserves, MBOE	Delhi Field MBOE	Giddings Field MBOE	Lopez Field MBOE	Oklahoma MBOE	Proved Total MBOE
June 30, 2013	13,545.5	35.1	185.8	—	13,766.4
Production	(164.2)	(12.0)	(1.1)	(0.4)	(177.7)
Revisions	(263.9)	16.2	—	0.4	(247.3)
Sales of minerals in place	—	—	(184.7)	—	(184.7)
Improved recovery, extensions and discoveries	—	132.8	—	—	132.8
June 30, 2014	13,117.4	172.1	—	—	13,289.5

Reconciliation of Changes in Probable Reserves by Major Property

Probable reserves, MBOE	Delhi Field MBOE	Giddings Field MBOE	Lopez Field MBOE	Oklahoma MBOE	Probable Total MBOE
June 30, 2013	7,412.3	—	530.8	3,281.0	11,224.1
Revisions	2,054.6	—	—	(3,281.0)	(1,226.4)
Sales of minerals in place	—	—	(530.8)	—	(530.8)
Improved recovery, extensions and discoveries	—	—	—	—	—
June 30, 2014	9,466.9	—	—	—	9,466.9

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Reconciliation of PV-10 to the Standardized Measure of Discounted Future Net Cash Flows

The following table provides a reconciliation of PV-10 of our proved properties to the Standardized Measure as shown in Note 18 of the consolidated financial statements.

	For the Years Ended June 30,	
	2014	2013
Estimated future net revenues	$671,972,966	$865,335,587
10% annual discount for estimated timing of future cash flows	352,227,569	406,373,713
Estimated future net revenues discounted at 10% (PV-10)	319,745,397	458,961,874
Estimated future income tax expenses discounted at 10%	(93,667,725)	(151,741,175)
Standardized Measure	$226,077,672	$307,220,699

The following table provides a reconciliation of PV-10 of each of our proved properties to the Standardized Measure as shown in Note 18 of the consolidated financial statements.

	For the Years Ended June 30,	
	2014	2013
Delhi Field	$318,076,654	$455,297,781
Giddings Field	1,668,743	513,816
Lopez Field	—	3,150,277
Estimated future net revenues discounted at 10% (PV-10)	$319,745,397	$458,961,874
Estimated future income tax expenses discounted at 10%	(93,667,725)	(151,741,175)
Standardized Measure	$226,077,672	$307,220,699

Additional information about the properties we own can be found in Item 1. Business.

Internal Controls Over Reserves Estimation Process and Qualifications of Technical Persons with Oversight for the Company's Overall Reserve Estimation Process

Our policies regarding internal controls over reserve estimates require reserves to be prepared by an independent engineering firm under the supervision of our Chief Executive Officer and Vice President of Operations and to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. We provide our engineering firm with property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Vice President of Operations and our Chief Executive Officer to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. The scope and results of our independent engineering firm's procedures, as well as their professional qualifications, are summarized in the letter included as exhibit 99.4 to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves were 5,319 MBOE at June 30, 2014 with associated future development costs of approximately $41.7 million. The 1,643 MBOE increase in proved undeveloped reserves from 3,676 MBOE as of June 30, 2013 is attributable to a 1,791 MBOE increase in reserves associated with the planned Delhi gas plant, partially offset by the sale of 148 MBOE of our Lopez Field properties.

At June 30, 2014, none of our proved undeveloped reserves, which are all at Delhi, have remained undeveloped for five years from the date of initial recognition and disclosure as proved undeveloped reserves. The operator has indicated spending plans related to development of these proved undeveloped reserves over the next three to four years, including installation of a gas processing plant. According to the operator, such spending will commence after our working interest reversion occurs.

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Sales Volumes, Average Sales Prices and Average Production Costs

The following table shows the Company's sales volumes and average sales prices received for crude oil, natural gas liquids, and natural gas for the periods indicated:

	Year Ended June 30, 2014		Year Ended June 30, 2013		Year Ended June 30, 2012	
Product	Volume	Price	Volume	Price	Volume	Price
Crude oil (Bbls)	169,783	$102.84	196,379	$105.34	151,081	$109.53
Natural gas liquids (Bbls)	3,516	$33.32	7,272	$34.81	12,611	$49.18
Natural gas (Mcf)	26,655	$3.60	139,006	$2.95	266,777	$2.98
Average price per BOE*	177,742	$99.43	226,819	$94.13	208,156	$86.29
Production costs	Amount	per BOE	Amount	per BOE	Amount	per BOE
Production costs, excluding ad valorem and production taxes	$1,156,011	$6.50	$1,713,833	$7.56	$1,708,235	$8.21
Total production costs, including ad valorem and production taxes	$1,193,573	$6.72	$1,780,738	$7.85	$1,774,999	$8.53

* BOE computed on units of production using a six to one conversion ratio of MCF's to barrels.

Drilling Activity

The following table sets forth our drilling activity during the past three fiscal years. During fiscal year 2014, we did not drill any new wells. During fiscal 2013, we completed 2 gross and 0.8 net wells in Kay County, Oklahoma. During fiscal 2012, we drilled and completed one gross and net well in the Lopez Field and declared dry two wells in Wagoner County, Oklahoma. One well drilled in the Lopez Field was temporarily inactive pending permitting.

	Year Ended June 30,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled						
Development	—	—	—	—	—	—
Exploratory	—	—	2.0	0.8	1.0	1.0
Total	—	—	2.0	0.8	1.0	1.0
Nonproductive dry wells drilled						
Development	—	—	1.0	0.2	—	—
Exploratory	—	—	—	—	—	—
Total	—	—	1.0	0.2	—	—

Present Activities

As of June 30, 2014, we had completed installation of our artificial lift technology in three non-operated wells, with at least two more wells scheduled in early fiscal 2015 under our contract with a large independent operator.

For further discussion, see "Highlights for our fiscal year 2014" and "Capital Budget" under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Delivery Commitments

As of June 30, 2014, we had no delivery or hedging commitments.

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Productive Wells and Developed Acreage

Area	Gross Developed Acres	Net Developed Acres	Gross (Net) Producing Wells		Inactive Producing Wells	
Giddings - GARP®	2,168	2,134	3.0	(2.9)	1.0	(0.9)
Giddings - Other	-	-	-	-	3.0	(3.0)
Mississippi Lime	1,399	630	1.0	(0.5)	3.0	(0.4)
Total	3,567	2,764	4.0	(3.4)	7.0	(4.3)

Our developed acreage at June 30, 2014 totaled 2,764 net acres, of which 2,134 net acres were in the Giddings Field comprising a 100% working interest in two producing wells, 99% working interest in one well subject to a back-in reversion of 22.5%, and a 90.5% working interest in one inactive well subject to a back-in reversion of 22.5%. We also have three shut-in wells in which we have a 100% working interest, all of which were plugged and abandoned subsequent to fiscal year end. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. We do not recognize net acres associated with our royalty interests in the EOR project at Delhi.

Undeveloped Acreage

As of June 30, 2014, we held approximately 20,279 gross and 5,522 net undeveloped acres in the Gulf Coast and Mid-Continent regions of the United States, as follows:

Undeveloped Acreage

Field/Area	Gross Acreage	Net Acreage
Kay County, Oklahoma	6,643	2,257
Delhi Field, Louisiana*	13,636	3,265
Total	20,279	5,522

* Includes from the surface of the Earth to the top of the Massive Anhydride, less and except the Delhi Holt Bryant CO_2 and Mengel Units. With respect to the Delhi Holt Bryant Unit, currently being redeveloped using CO_2-EOR operations within this same acreage, we currently own royalty interests aggregating approximately 7.4%. Separately, we own a 23.9% reversionary working interest (19.1% net revenue interest) that will revert to us, as, if and when payout occurs, as defined. We are not the operator of the Delhi CO_2-EOR project.

Our net undeveloped acreage in the Delhi Field is held by production and does not expire so long as production is maintained in the unit. Our acreage in Oklahoma is all subject to expiration in fiscal 2015, if not renewed or extended.

For more complete information regarding current year activities, including crude oil and natural gas production, refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Item 3. Legal Proceedings

See Note 15—Commitments and Contingencies under Item 8. Financial Statements for a description of legal proceedings.

Item 4. Mine Safety Disclosures

Not Applicable.

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PART II

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

Common Stock

Our common stock is currently traded on the NYSE MKT under the ticker symbol "EPM".

We initiated trading of our common stock on the OTC Bulletin Board in May 2004, under the symbol "NGSY". On July 17, 2006 we qualified for trading on the American Stock Exchange. The American Stock Exchange was acquired by the NYSE Euronext (NYX) in 2008 and is now known as NYSE MKT. The following table shows, for each quarter of the fiscal years ended June 30, 2014 and 2013, the high and low sales prices for EPM as reported by the NYSE MKT.

NYSE MKT: EPM

2014:	High	Low
Fourth quarter ended June 30, 2014	$13.15	$9.92
Third quarter ended March 31, 2014	$13.83	$11.56
Second quarter ended December 31, 2013	$12.77	$11.01
First quarter ended September 30, 2013	$12.59	$10.68

2013:	High	Low
Fourth quarter ended June 30, 2013	$11.50	$9.60
Third quarter ended March 31, 2013	$11.09	$8.06
Second quarter ended December 31, 2012	$8.40	$7.48
First quarter ended September 30, 2012	$8.99	$7.70

Shares Outstanding and Holders

As of June 30, 2014, there were 32,615,646 shares of common stock issued and outstanding, held by approximately 350 holders of record.

Dividends

We we began paying cash dividends on our common stock in December 2013, at a rate of $0.10 per share. As of June 30, 2014, we had paid three quarterly dividends on our common stock. All dividends on our Series "A" Perpetual Preferred stock have been timely declared and paid. Any future determination with regard to the payment of dividends will be at the discretion of the board of directors and will be dependent upon our future earnings, financial condition, applicable dividend restrictions and capital requirements and other factors deemed relevant by the board of directors. Under our current revolving credit facility, an existing loan balance and/or letter of credit commitment would restrict our ability to pay common stock dividends.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from June 30, 2009 to June 30, 2014 with the cumulative total return of the S&P 500 Index and the SIG Oil Exploration and Production Index of publicly traded companies over the same period. The graph assumes that $100 was invested on June 30, 2009 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any. The graph is presented in accordance with requirements of the SEC. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.

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Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding Options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(1)
Equity compensation plans approved by security holders	178,061	(1)	$ 2.08	812,281
Equity compensation plans not approved by security holders	—		$ —	—
Total	178,061		$ 2.08	812,281

(1) As of June 30, 2014, there were 178,061 shares of common stock issuable upon exercise of outstanding stock options. The Amended and Restated 2004 Stock Plan (the "Plan") provides for the issuance of a total of 6,500,000 common shares. As of June 30, 2014, 3,767,134 common shares had been issued upon the exercise of stock options, 1,742,524 shares of restricted common stock had been issued under the Plan (of which 140,067 were unvested as of June 30, 2014) and 812,281 shares of common stock were available for future grants under the Plan.

Issuer Purchases of Equity Securities

During the fourth fiscal quarter ended June 30, 2014, the Company received shares of common stock from certain of its employees and directors which were surrendered in exchange for their payroll tax liabilities arising from vestings of restricted stock. The acquisition cost per share reflected the weighted-average market price of the Company's shares at the dates vested. Such shares were initially recorded as treasury stock, then subsequently canceled.

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Period	(a) Total Number of Shares (or Units) Purchased	(b) Average Price Paid per Share (or Units)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
April 1, 2014 to April 30, 2014	99 shares of Common Stock	$12.73	Not applicable	Not applicable
May 1, 2014 to May 31, 2014	none	—	—	—
June 1, 2014 to June 30, 2014	5,590 shares of Common Stock	$11.15	Not applicable	Not applicable

Item 6. Selected Financial Data

The selected consolidated financial data, set forth below should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this report.

	June 30, 2014	2013	2012	2011	2010
Income Statement Data					
Revenues	$17,673,508	$21,349,920	$17,962,038	$7,530,875	$5,021,901
Artificial lift technology costs	609,221	390,238	124,703	—	—
Production costs - other properties	584,352	1,390,500	1,650,296	1,379,327	1,665,079
Depreciation, depletion, and amortization	1,228,685	1,300,207	1,136,974	563,104	1,818,110
Accretion expense	41,626	72,312	77,505	59,913	61,054
General and administrative expense	8,388,291	7,495,309	6,143,286	5,335,384	5,092,243
Restructuring charges	1,293,186	—	—	—	—
Income (loss) from operations	5,528,147	10,701,354	8,829,274	193,147	(3,614,585)
Other income (expense)	(38,836)	(43,165)	3,778	14,214	55,054
Income tax provision (benefit)	1,891,998	4,029,761	3,700,922	448,914	(1,171,824)
Net income (loss) attributable to the Company	$3,597,313	$6,628,428	$5,132,130	$(241,553)	$(2,387,707)
Dividends on Series A Preferred Stock	674,302	674,302	630,391	—	—
Net income (loss) attributable to common shareholders	$2,923,011	$5,954,126	$4,501,739	$(241,553)	$(2,387,707)
Earnings per share:					
Basic	$0.09	$0.21	$0.16	$(0.01)	$(0.09)
Diluted	$0.09	$0.19	$0.14	$(0.01)	$(0.09)

	June 30, 2014	June 30, 2013	June 30, 2012	June 30, 2011	June 30, 2010
Balance Sheet Data					
Total current assets	$26,304,803	$27,436,076	$16,769,789	$6,357,840	$6,229,351
Total assets	65,015,752	66,556,296	58,955,486	39,951,953	37,195,075
Total current liabilities	2,999,726	2,632,750	5,088,917	2,211,932	1,287,699

Total liabilities	13,138,230	11,720,135	12,332,698	6,487,196	5,717,882
Stockholders' equity	51,877,522	54,836,161	46,622,788	33,464,757	31,477,193
Common stock outstanding	32,615,646	28,608,969	27,882,224	27,612,916	27,061,376

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

Executive Overview

General

We are engaged primarily in the development of incremental oil and gas reserves within known oil and gas resources for our shareholders and customers utilizing conventional and proprietary technology. We are focused on increasing underlying asset values on a per share basis. In doing so, we depend on a conservative capital structure, allowing us to maintain control of our assets for the benefit of our shareholders, including a substantial ownership by our directors, officers and staff. By policy, every employee and director maintains a beneficial ownership of our common stock.

Our strategy is to grow the value of our Delhi asset to maximize the value realized by our shareholders while commercializing our patented GARP® artificial lift technology for recovering incremental oil and gas reserves in mature fields.

We expect to fund our fiscal 2015 capital program from working capital and net cash flows from our properties.

Highlights for our fiscal year 2014

Finances

- We initiated a common stock dividend in fiscal 2014. We paid a total of $9.7 million in common stock dividends during the fiscal year.
- Working capital was $23.3 million at June 30, 2014 compared to $24.8 million at the prior year end. At June 30, 2014, working capital included $24.0 million of cash.
- We remained debt free. All of our expenditures were funded solely by working capital and we ended our fiscal year with no funded debt.
- Stock option exercises raised $3.3 million in cash proceeds, and resulted in a tax loss carryforward of $27.6 million which can be used to offset future income tax payments. The tax benefits related to stock-based compensation will not reduce our future income tax expenses for financial reporting purposes, but will instead increase our stockholders' equity. In addition, we have percentage depletion carryforwards of $9.1 million.
- Dividend distributions to preferred and common shareholders will be characterized as return of capital and not taxable dividends for the fiscal 2014. The loss carryforwards from stock option exercises caused a deficit in our current year tax earnings and profits, as defined, making cash dividends a return of capital to our shareholders.

Operations

- Our fiscal 2014 net income was $2.9 million, a 51% decline from fiscal 2013 net income of $6.0 million. During fiscal 2014, we incurred pre-tax restructuring expenses and other non-recurring charges of $2.7 million in connection with our new corporate strategy, the retirement of a corporate officer and the exercise of substantially all of our outstanding stock options. We expect to see reduced corporate overhead going into fiscal 2015.

- Total revenues were $17.7 million, a 17% decrease from $21.3 million in fiscal 2013. During fiscal 2014, we completed the divestiture of substantially all of our non-core oil and gas properties, causing a drop of $1.6 million in revenue. Our production and revenues from the Delhi Field were also down $2.3 million as a result of the June 2013 fluids release (the “June 2013 Event” discussed below).

- Artificial lift technology revenues were $0.6 million in fiscal 2014, a 66% increase from $0.4 million in fiscal 2013.

Oil & Gas Reserves

- Combined Delhi Proved and Probable oil equivalent volumes at June 30, 2014 increased to 22.6 MMBOE, an 8% increase over the previous year;
- Reserves volumes in the immediate area of the June 2013 Event and within the Delhi town limits were re-categorized from Proved Reserves to Probable Reserves, due to the operator’s current forecast of deferred CO2 injection;
- Combined Proved and Probable future net revenues remain essentially unchanged, despite a lower trailing average oil price than that used in 2013, while the combined PV 10* of $454 million is 20% lower than the previous year, due

primarily to a more conservative operating plan that defers a portion of forecast production into later periods and a lower peak production rate;

- Reserve Life Index** for Proved Oil Reserves at Delhi is approximately 18 years;
- The operator has elected to pursue a more conservative development and operating plan at Delhi, resulting in growing annual production volumes through 2022 with a projected peak rate expected to be 20% lower than forecasts from the previous year; and
- Proved Reserves of 13.3 MMBOE are 79% oil, 17% natural gas liquids and 4% natural gas.

	Proved			Probable		
	2014	2013	Change	2014	2013	Change
Reserves MMBOE	13.3	13.8	(4)%	9.5	11.2	(15)%
% Developed	60%	73%	(18)%	43%	32%	34%
Liquids %	96%	100%	(4)%	97%	80%	21%
PV-10* ($MM)	$320	$459	(30)%	$136	$135	1%

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* PV-10 of Proved reserves is a pre-tax non-GAAP measure. We have included a reconciliation of PV-10 to the unaudited after-tax Standardized Measure of Discounted Future Net Cash Flows, which is the most directly comparable financial measure calculated in accordance with GAAP, in Item 2. "Properties." We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful and relevant information to investors because of its wide use by analysts and investors in evaluating the relative monetary significance of oil and natural gas properties, and as a basis for comparison of the relative size and value of our reserves to other companies' reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it 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 as defined under GAAP, and reconciled below. Probable and Possible reserves are not recognized by GAAP, and therefore the PV-10 of Probable and Possible reserves cannot be reconciled to a GAAP measure.

** Reserve Life Index is a relative measure of the average life of a Company's reserves calculated as the remaining reserves divided by the current rate of production. In our calculation we have used total Proved oil reserves divided by expected oil production in the first 12 months of the reserve report, calculated on a gross basis so as not to be affected by the timing of the working interest reversion. Natural gas and NGL reserves and production were not considered material or relevant for the purpose of this calculation as they are currently undeveloped. We believe that this measure is relevant to understanding and analyzing our reserve base and is useful to investors and analysts in comparing our company to others in the industry. This measure is not an absolute measure of the expected life of our reserves, nor is it intended to convey information about any specific event or time in the future.

Projects

Additional property and project information is included under Item 1. Business, Item 2. Properties, Notes to the Financial Statements and Exhibit 99.4 of this Form 10-K.

Delhi Field EOR—Northeast Louisiana

Our reserves in the Delhi Field were impacted by the June 2013 Event, which consisted of the uncontrolled release of CO_2, water, natural gas and a small amount of oil from one or more previously plugged wells in the southwest part of the Field. The operator has fully remediated the affected area, but that portion of the Field has been converted for the foreseeable future from CO_2 flood to water flood. This has also prompted the operator to pursue a more conservative development plan for the balance of the field. The operational effects include:

- Reducing reservoir pressure that will result in production over a longer period of time than previously forecast and a lower peak production rate;
- Deferring CO_2 injection in the immediate area of the June 2013 Event in favor of a water flood; and

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- Deferring CO_2 injection in the immediate area of the town of Delhi in the eastern, currently undeveloped portion of the project.

Reducing reservoir pressure by slowing the pace of CO_2 injection is expected to lower and delay the projected peak oil production rate, but results in a much flatter decline curve. Deferring CO_2 injection in two areas of the field has also resulted in the reclassification of related developed and undeveloped reserves from the Proved category to Probable category, primarily as a result of CO_2 injections currently projected to occur beyond the SEC's five-year limitation for Proved Reserves development projects. There is uncertainty as to when CO_2 injections may be re-established or initiated in the affected areas, which may be sooner or later than currently projected.

The decline in Proved Reserves resulting from reduced injection pressure and deferred development was partially offset, in volumes, by the addition of incremental proved gas plant volumes, with forecasts of a more robust natural gas liquids ("NGL") recovery than projected in the previous year's estimate. The combined impacts on PV-10* of the lower peak production rate, later date of peak rate and re-categorization of reserves resulted in a decrease of our Proved PV-10* by 30% to $318 million. Due to the re-categorization, Probable volumes and related PV-10* increased 28% and 24%, respectively, to 9.5 MMBOE and $136 million, respectively. Consequently, the aggregate impact on Proved and Probable reserves was an 8% increase in combined volumes to 22.6 MMBOE and a 20% decrease in combined PV-10* to $454 million.

Possible reserves volumes at Delhi decreased by 20% to 3.0 MMBOE and PV-10* declined by 38% to $20 million, both primarily due to the incremental recovery factor being reduced from 3% to 2% of original oil in place and the projected slower production pace.

Gross production at Delhi in the fourth quarter of fiscal 2014 was 5,956 BOPD, down slightly from the third fiscal quarter's 6,172 BOPD due primarily to normal plant maintenance during the fourth quarter and no material development capital expenditures since early calendar 2013. The reduction in production from the 7,188 BOPD rate in the fourth fiscal quarter of 2013 is primarily attributable to the June 2013 Event. In addition, the operator's current plans are to produce the Field at a lower CO_2 injection pressure, which is expected to reduce peak production rates, but extend production over a longer life.

The operator has better defined its plans to process recycled gas to recover substantially all of the natural gas liquids and methane beginning in the second half of calendar 2015. Our previous report was based on a more limited recovery of only heavier C5+ liquids. This new plan should substantially increase recovery volumes and improve the gas plant economics while simultaneously improving CO_2 flood efficiency.

Looking forward, the operator has said that it will not commence material new capital expenditures until reversion of our working interest, which they expect to occur in the fourth quarter of calendar 2014. We now expect Delhi production to peak in 2021-2022. Consequently, our Delhi PV-10* is now expected to increase over time to its maximum value around the first quarter of calendar 2018, about two years later than previously forecast. At that point, we are projected to have generated approximately $120 million of net cash flow from the Field after capital expenditures.

GARP® - Artificial Lift Technology

For the first time we are separately disclosing reserves associated with wells equipped with our GARP® technology. Proved Reserves attributable to Company-operated GARP® installations completed during the past three years include 172 thousand barrels of oil equivalent ("MBOE") of Proved Reserves with PV-10* of $1.7 million. Based on Proved Reserves and cumulative production to date only, our GARP® technology has added reserves at a cost of less than $4.00 per barrel of oil equivalent ("BOE").

With respect to the previously announced contract to install GARP® for a third party operator, we have successfully completed installations on a total of three wells and we expect to continue installations on another two wells in the near future. Two of the three wells are producing at commercial rates which are more than double the rates prior to installation, but have not yet fully stabilized. One of the three wells, which was not producing at commercial rates prior to installation, appears to have an obstruction in the lateral or a depleted reservoir which is severely restricting fluid production. We intend to pull the GARP® equipment out of that well and use it in a future installation. We attempted installation on a fourth well, but encountered an obstruction in the horizontal section of the wellbore and abandoned the operation.

Other Fields

During the year we divested noncore properties in the South Texas Lopez Field and scheduled for divestment our Mississippi Lime properties in Oklahoma. Approximately 0.2 MMBOE of Proved Reserves and 3.8 MMBOE of Probable Reserves were associated with these assets as of June 30, 2013 and are no longer included in our year-end reserves. Consequently, all of our Probable and Possible Reserves are located in the Delhi Field.

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Liquidity and Capital Resources

At June 30, 2014, our working capital was $23.3 million compared to $24.8 million at June 30, 2013. The $1.5 million working capital decrease was due primarily to $1.2 million of lower cash and certificates of deposit and $0.4 million of increased current liabilities impacted by accruals for restructuring and an officer retirement. During our fiscal year ended June 30, 2014, we incurred oil and gas capital expenditures of $0.8 million and capital expenditures of $0.4 million for artificial lift technology equipment. Principal development activities related to GARP® wells at Giddings and expenditures on existing Mississippi Lime wells. During the year, we realized $3.3 million of proceeds from stock option and warrant exercises as well as $0.5 million of proceeds primarily from the sale of our non-core Lopez properties.

Cash Flows from Operating Activities

For the year ended June 30, 2014, cash flows provided by operating activities were $8.1 million, reflecting $7.7 million provided by operations before $0.4 million provided by other working capital changes. Of the $7.7 million provided before working capital changes, $3.6 million was due to net income and $4.1 million was attributable to non-cash expenses.

For the year ended June 30, 2013, cash flows provided by operating activities were $11.9 million, reflecting $6.6 million of net income together with $5.3 million provided by non-cash expenses, including $2.5 million from deferred income taxes, $1.5 million from stock compensation, and $1.3 million from depreciation, depletion and amortization.

Cash flows provided by operating activities for the year ended June 30, 2012 were $10.4 million, reflecting $5.2 million of net income and $5.2 million provided by noncash expenses. Working capital items were essentially unchanged from the prior year. Included in noncash expenses were $1.2 million of depreciation, depletion and amortization, $1.5 million of stock-based compensation, and $2.5 million of deferred income taxes.

Cash Flows from Investing Activities

For the year ended June 30, 2014, cash paid for oil and gas capital expenditures was $1.3 million, primarily for development activities related to GARP® wells in Giddings and continuing costs for the Sneath and Hendrickson wells drilled in the Mississippi Lime during the prior year. We received approximately $542,000 of proceeds from asset sales, including $402,500 from the December sale of our South Texas properties, and $250,000 of cash from the maturity of a certificate of deposit.

Cash paid for oil and gas capital expenditures during the year ended June 30, 2013 was $4.9 million. Of these expenditures, $0.7 million was for leasehold acquisitions, principally in the Mississippi Lime, and $4.2 million was for development activities. Development activities were predominantly in the Mississippi Lime, where one salt water disposal well and two wells were drilled. In Giddings, expenditures were centered on adding three new GARP® wells. An inflow of $3.5 million was received for proceeds from the sales of a portion of our Giddings exploration and production properties. In December 2012, an expiring $250,000 certificate of deposit was rolled over beginning a new annual term.

Cash paid for oil and gas capital expenditures during the year ended June 30, 2012 was $7.0 million. Of these expenditures, $3.7 million was for leasehold acquisitions, principally in the Mississippi Lime in Oklahoma, and $3.3 million was for development activities. Development expenditures were primarily in the Lopez Field where four wells were drilled with remaining expenditures made in the Mississippi Lime and the Giddings Field in Texas.

At June 30, 2012, we had advanced $224,206 of cash for its share of development costs to be incurred by its joint venture partner in the Mississippi Lime play and recorded a $1,142,715 advance to be paid subsequent to June 30, 2012. During the year ended June 30, 2012, we received $0.8 million for the sale of a portion of our Woodbine lease rights.

Oil and gas capital expenditures incurred, which includes accrued expenditures, were $0.9 million, $3.4 million, and $8.9 million, respectively, for the years ended June 30, 2014, 2013, and 2012. These amounts can be reconciled to cash capital expenditures on their respective cash flow statements by adjusting them for related non-cash items presented at Note 10—"Supplemental Cash Flow Information".

Cash Flows from Financing Activities

During the year ended June 30, 2014, we used $8.3 million in cash for financing activities, reflecting $9.7 million of common stock dividend payments, $0.7 million of preferred stock dividends and $1.7 million of treasury stock acquired through the surrender of shares by certain officers and employees in satisfaction of payroll liabilities related to stock-based compensation, partially offset by cash inflows of $0.5 million from a tax benefit related to stock-based compensation and $3.3 million from stock option exercises.

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During the year ended June 30, 2013, we paid preferred dividends of $0.7 million and acquired $0.1 million of treasury stock through the surrender of shares by certain officers and employees in satisfaction of payroll liabilities related to stock-based compensation, as described at Note 8—"Stockholders' Equity." A tax benefit related to stock-based compensation provided $0.8 million.

During the year ended June 30, 2012, we received $6.9 million of net proceeds from the issuance of 317,319 shares of our 8.5% Series A perpetual preferred stock after all offering costs and we paid $0.6 million of dividends thereon. We incurred deferred loan costs of $0.2 million during 2012 in connection with an unsecured revolving credit agreement, which has current availability of $5.0 million.

Capital Budget

Delhi Field

With reversion of our 23.9% working interest in Delhi expected to occur during the fourth quarter of calendar 2014, we will begin funding our share of capital expenditures in the Field. Projected capital expenditures over the next two fiscal years are currently expected to total approximately $25-27 million. This timing of this spending is dependent on the date of reversion of our working interest and the pace of project development by the operator of the Field. Of this total, approximately $15-17 million is for the gas processing plant and approximately $10 million is for the roll-out of the next phase of the CO_2 project. We expect these costs to be incurred over portions of the next two fiscal years. Total spending based on proved reserves in the reserve report, net to our interest, is forecast to be approximately $45 million over the next four years, which includes the projects above plus further expansion of the CO_2 flood pattern. We expect that cash flows from the our interests in the Field will be significantly in excess of the net capital expenditures required.

GARP® - Artificial Lift Technology

Our marketing and business plans for commercializing this artificial lift technology continue to evolve. During the early stages of commercializing the technology, we used it for our own account in operated wells and under farm-outs from other operators. During 2014, we entered into a risk-sharing contract under which we were responsible for funding the majority of the equipment and installation costs in exchange for fees based on the net profits from the wells. Going forward, we may continue to install the technology for our own account and under risk-sharing arrangements. However, we currently expect a greater percentage of our future revenues to result from contracts where we are paid on a fee basis, rather than under risk-sharing arrangements or in our own wells. Accordingly, we currently expect that our capital requirements for artificial lift technology operations will be relatively modest.

Liquidity Outlook

Funding for all capital expenditures is expected to be met from current working capital and cash flows from operations. Our preference is to remain debt free, but we do have access to a $5 million unsecured revolving line of credit and are in discussions to convert this line to a senior secured facility with up to $30 million of capacity. This facility is intended primarily to provide a standby source of liquidity to meet future capital expenditures at Delhi or other future capital needs or opportunities.

Payment of cash dividends on our common stock remains an important aspect of our financial strategy and it is our goal to maintain or increase our dividends. We expect that the excess cash flow from the Delhi Field, after reversion of our working interest, will permit the Board of Directors to consider prudent increases in the level of our dividend payout.

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Results of Operations

The following table sets forth certain financial information with respect to our oil and natural gas operations:

	Year Ended June 30,		
	2014	2013	2012
Delhi field:			
Crude oil revenues	$16,908,666	$19,219,036	$15,143,770
Crude oil volumes (Bbl)	164,224	180,658	136,074
Average price per Bbl	$102.96	$106.38	$111.29
Artificial lift technology:			
Crude oil revenues	$414,270	$323,488	$113,430
NGL revenues	115,172	16,661	15,148
Natural gas revenues	93,890	34,914	3,766
Total revenues	$623,332	$375,063	$132,344
Crude oil volumes (Bbl)	4,115	3,476	1,199
NGL volumes (Bbl)	3,460	432	304
Natural gas volumes (Mcf)	26,105	10,531	1,543
Equivalent volumes (BOE)	11,927	5,664	1,760
Crude oil price per Bbl	$100.67	$93.06	$94.60
NGL price per Bbl	$33.29	$38.57	$49.83
Natural gas price per Mcf	$3.60	$3.32	$2.44
Equivalent price per BOE	$52.26	$66.22	$75.20
Artificial lift production costs	$609,221	$390,238	$124,703
Production costs per BOE	51.08	68.90	70.85
Other properties:			
Revenues	$141,510	$1,755,821	$2,685,924
Equivalent volumes (BOE)	1,591	40,497	70,322
Equivalent price per BOE	$88.94	$43.36	$38.19
Production costs	$584,352	$1,390,500	$1,650,296
Production costs per BOE	$367.29	$34.34	$23.47
Combined:			
Oil and gas DD&A (a)	$1,192,370	$1,255,209	$1,087,020
Oil and gas DD&A per BOE	$6.71	$5.53	$5.22

(a) Excludes totals of depreciation of office equipment, furniture and fixtures, and amortization of other assets of $36,315 and $44,998 and $49,954 for the years ended June 30, 2014, 2013, and 2012, respectively.

Year ended June 30, 2014 compared with the Year ended June 30, 2013

Net Income Available to Common Shareholders. For the year ended June 30, 2014, we generated net income of $2.9 million or $0.09 per diluted share, (which includes a $1.3 million restructuring charge, $1.4 million of non-recurring charges related to stock option exercises and the retirement of the Company’s chief financial officer) on total oil and natural gas revenues of $17.7 million. For the year ended June 30, 2014, non-cash stock compensation expense was $1.7 million of which $203,861 related to the retirement charge. This compares to a net income of $6.0 million, or $0.19 per diluted share, (which includes $1.5 million of non-cash stock-based compensation expense) on total oil and natural gas revenues of $21.3 million for the

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corresponding year-ago period. The earnings decline is due to lower revenue, higher G&A, and a current year restructuring charge, partially offset by lower lease operating expense and income taxes. Additional details of the components of net income are explained in greater detail below.

Delhi Field. Revenue decreased 12% to $16.9 million primarily because of a 9% volume decline attributable to the June 2013 Event, together with a 3% lower price per BOE.

Artificial Lift Technology. Revenue increased 66% to $0.6 million reflecting a 110% BOE volume increase, primarily due to the new Philip well, partially offset by a 21% decrease in price per BOE primarily influenced by a higher percentage of natural gas production.

Other Properties. Revenue decreased by 92% to $0.1 million due to the prior fiscal year sales of non-core Giddings Field properties and the sale of Lopez Field properties in December 2013.

Artificial Lift Production Costs. Expenses increased 56% to $0.6 million due to the new Philip and Appelt wells.

Other Properties Production Costs. Expenses decreased 58% to $0.6 million due the prior fiscal year sales of Giddings Field properties and the December 2013 sale of our South Texas Lopez Field. We had continuing workover and testing costs on our Mississippi Lime project during 2014 which have now been terminated.

General and Administrative Expenses (“G&A”). G&A expenses, including $1.4 million of one-time charges, increased 12% to $8.4 million during the year ended June 30, 2014 from $7.5 million in the prior year. The $0.9 million increase was primarily due to approximately $672,000 of higher compensation and benefits impacted by an officer's retirement, $146,000 of higher transaction expenses, $121,000 of lower absorption to drilling projects and $90,000 in higher consulting expense, partially offset by lower stock compensation expense of $179,000. Stock-based compensation was $1.4 million (16% of total G&A) for the year ended June 30, 2014 compared to $1.5 million (21% of total G&A) for the year ended June 30, 2013.

Restructuring Charges. The Company recorded $1.3 million of restructuring expense in December 2013 primarily reflecting $956,000 of termination benefits to be paid from January to December 2014 and $376,000 of non-cash stock compensation expense for accelerated restricted stock vesting for terminated employees. See Note 5 — Restructuring.

Oil and Gas Depreciation, Depletion & Amortization Expense (“DD&A”). DD&A decreased by 5% to $1.2 million for the year ended June 30, 2014, compared to $1.3 million for the prior year. This change was principally due to a 21% increase in depletion rate to $6.71 per BOE, partially offset by a 22% volume decrease.

Year ended June 30, 2013 compared with the Year ended June 30, 2012

Net income attributable to common shareholders. For the year ended June 30, 2013, we reported net income of $6.0 million or $0.19 income per diluted share (which includes $1.5 million of non-cash stock-based compensation expense) on total oil and natural gas revenues of $21.3 million. This compares to net income of $4.5 million, or $0.14 income per diluted share (which includes $1.5 million of non-cash stock-based compensation expense) on total oil and natural gas revenues of $18.0 million for the year ended June 30, 2012. The difference was primarily due to an increase in revenues of $3.4 million partially offset by $1.5 million of increased operating expenses. Additional details of earnings components are explained in greater detail below.

Delhi Field. Revenue increased 27% to $19.2 million because of a 33% volume increase partially offset by a 4% price per bbl decline.

Artificial Lift Technology. Revenue increased 183% to $0.4 million due to a 222% BOE volume increase, primarily due to a full year of production from the Morgan Kovar well completed during the prior fiscal year, partially offset by a 12% decrease in price per BOE impacted by an increase in the percentage of natural gas production.

Other Properties. Revenue decreased by 35% to $1.8 million for the year ended June 30, 2013 due to the December 2012 sale of Giddings Field properties.

Artificial Lift Production Costs. Expenses increased 213% to $0.4 million for fiscal 2013 reflecting a full year of operations for the Selected Lands #1 and #2 wells, which were completed in the fourth calendar quarter of 2011.

Other Properties Production Costs. Expenses decreased 16% to $1.4 million for the year ended June 30, 2013 principally due to the December 2012 sale of Giddings Field properties.

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General and Administrative Expenses ("G&A"). G&A expenses increased 22% to $7.5 million for the year ended June 30, 2013, compared to $6.1 million for the year ended June 30, 2012. The increase was due principally to $361,000 for higher bonus expense, $287,000 for higher legal expense (principally litigation), $232,000 for salaries and benefits, $124,000 for compliance costs, $87,000 for divestiture transaction fees, and $73,000 for board of director fees. Stock-based compensation was $1.5 million (21% of total G&A) and $1.4 million (24% of total G&A) for the years ended June 30, 2013 and 2012, respectively, is an integral part of total staff compensation utilized to recruit quality staff from other, more established companies and, as a result, will likely continue to be a significant component of our G&A costs.

Oil and Gas Depreciation, Depletion & Amortization Expense (“DD&A”). DD&A increased by 14% to $1.3 million for the year ended June 30, 2013, compared to $1.1 million for the prior year. The increase is primarily due to a 9% increase in volumes, and a 6% higher annual depletion rate of $5.53 per BOE. The higher depletion rate is primarily due to higher Delhi future development costs partially offset by lower future development costs due to Giddings properties divested during the current year.

Other Economic Factors

Inflation. Although the general inflation rate in the United States, as measured by the Consumer Price Index and the Producer Price Index, has been relatively low in recent years, the oil and gas industry has experienced unusually volatile price movements in commodity prices, vendor goods and oilfield services. Prices for drilling and oilfield services, oilfield equipment, tubulars, labor, expertise and other services greatly impact our lease operating expenses and our capital expenditures. During fiscal 2014, we saw modest cost increases in certain oilfield services and materials compared to prior years. Product prices, operating costs and development costs may not always move in tandem.

Known Trends and Uncertainties. General worldwide economic conditions continue to be uncertain and volatile. Concerns over uncertain future economic growth are affecting numerous industries, companies, as well as consumers, which impact demand for crude oil and natural gas. If demand decreases in the future, it may put downward pressure on crude oil and natural gas prices, thereby lowering our revenues and working capital going forward. In addition, our lease operating expenses and their percentage of our revenues are likely to increase as reversion of our back-in interest at Delhi or other additions to our working interest production that would dilute extraordinary margins we have enjoyed from our mineral and overriding royalty interests at Delhi.

Seasonality. Our business is generally not directly seasonal, except for instances when weather conditions may adversely affect access to our properties or delivery of our petroleum products. Although we do not generally modify our production for changes in market demand, we do experience seasonality in the product prices we receive, driven by summer cooling and driving, winter heating, and extremes in seasonal weather including hurricanes that may substantially affect oil and natural gas production and imports.

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2014, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligations					
Operating lease	331,273	159,011	159,011	13,251	—
Other Obligations					
Asset retirement obligations	352,215	146,703	—	—	205,512
Total obligations	$683,488	$305,714	$159,011	$13,251	$205,512

We have entered into employment agreements with two of the Company's senior executives. The employment contracts provide for severance payments in the event of termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, as defined. The agreements provide for the payment of base pay and certain medical and disability benefits for periods ranging form 6 months to 1 year after termination. The total contingent obligations under the employment contracts as of June 30, 2014 was approximately $591,000.

Critical Accounting Policies and Estimates

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The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires that we select certain accounting policies and make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. These policies, together with our estimates have a significant effect on our consolidated financial statements. Our significant accounting policies are included in Note 2 to the consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2014, we had no unevaluated properties costs.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense, and the estimated future net cash flows associated with those proved reserves is the basis in determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, additional development activity, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare our reserve estimates, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and / or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves, affecting our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves and Standardized Measure as of June 30, 2014 would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company's proved reserve estimates at June 30, 2014 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $53,000, $116,000 and $186,000, respectively.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and gas reserves. The rule allows consideration of new technologies in evaluating reserves, generally limits the designation of proved reserves to those projects forecast to be commenced within five years of the end of the period, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and gas operations, and revises accounting for the limitation on capitalized costs for full cost companies.

Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating loss). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of June 30, 2014, we have recorded a valuation allowance for the portion of our net operating loss that is limited by IRS Section 382.

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Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making the assessment of the ultimate realization of deferred tax assets. Based upon the level of historical taxable income and projections for future taxable income over the periods for which the deferred tax assets are deductible, as of end of the current fiscal year, we believe that it is more likely than not that the Company will realize the benefits of its net deferred tax assets. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable.

Stock-based Compensation. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option pricing model. This valuation method requires the input of certain assumptions, including expected stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of the Company's stock. The risk-free interest rate used is the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Because of our limited trading experience of our common stock and limited exercise history of our stock option awards, estimating the volatility and expected term is very subjective. We base our estimate of our expected future volatility on peer companies whose common stock has been trading longer than ours, along with our own limited trading history while operating as an oil and natural gas producer. Future estimates of our stock volatility could be substantially different from our current estimate, which could significantly affect the amount of expense we recognize for our stock-based compensation awards.

Off Balance Sheet Arrangements

The Company has no off-balance sheet arrangements as of June 30, 2014.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risks

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Commodity Price Risk

Our most significant market risk is the pricing for crude oil, natural gas and NGLs. We expect energy prices to remain volatile and unpredictable. If energy prices decline significantly, revenues and cash flow would significantly decline. In addition, a non-cash write-down of our oil and gas properties could be required under full cost accounting rules if future oil and gas commodity prices sustained a significant decline. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as, if and when needed. Although our current production base may not be sufficient enough to effectively allow hedging, we may use derivative instruments to hedge our commodity price risk.

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Item 8. Financial Statements

Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders
Evolution Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2014 and 2013, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Evolution Petroleum Corporation and subsidiaries as of June 30, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2014, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Evolution Petroleum Corporation and subsidiaries' internal control over financial reporting as of June 30, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992, and our report dated September 12, 2014 expressed an unqualified opinion on the effectiveness of Evolution Petroleum Corporation's internal control over financial reporting.

Hein & Associates LLP
Houston, Texas
September 12, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation

We have audited Evolution Petroleum Corporation's internal control over financial reporting as of June 30, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Evolution Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Evolution Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of June 30, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2014 and 2013, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2014, and our report dated September 12, 2014, expressed an unqualified opinion.

Hein & Associates LLP
Houston, Texas
September 12, 2014

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Balance Sheets

	June 30, 2014	June 30, 2013
Assets		
Current assets		
Cash and cash equivalents	$23,940,514	$24,928,585
Certificates of deposit	—	250,000
Receivables		
Oil and natural gas sales	1,456,146	1,632,853
Joint interest partner	—	49,063
Income taxes	—	281,970
Other	1,066	918
Deferred tax asset	159,624	26,133
Prepaid expenses and other current assets	747,453	266,554
Total current assets	26,304,803	27,436,076
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties—full-cost method of accounting, of which $4,112,704 was excluded from amortization at June 30, 2013	37,822,070	38,789,032
Other property and equipment	424,827	52,217
Total property and equipment	38,246,897	38,841,249
Advances to joint interest operating partner	—	26,059
Other assets	464,052	252,912
Total assets	$65,015,752	$66,556,296
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$441,722	$769,099
State and federal taxes payable	—	233,548
Accrued liabilities and other	2,558,004	1,630,103
Total current liabilities	2,999,726	2,632,750
Long term liabilities		
Deferred income taxes	9,897,272	8,418,969
Asset retirement obligations	205,512	615,551
Deferred rent	35,720	52,865
Total liabilities	13,138,230	11,720,135
Commitments and contingencies (Note 15)		
Stockholders' equity		
Preferred stock, par value $0.001; 5,000,000 shares authorized: 8.5% Series A Cumulative Preferred Stock, 1,000,000 shares designated, 317,319 shares issued and outstanding at June 30, 2014 and 2013, respectively, with a total liquidation preference of $7,932,975 ($25.00 per share)	317	317
Common stock; par value $0.001; 100,000,000 shares authorized; issued 32,615,646 shares at June 30, 2014, and 29,410,858 at June 30, 2013; outstanding 32,615,646 shares and 28,608,969 shares as of June 30, 2014 and 2013, respectively	32,615	29,410
Additional paid-in capital	34,632,377	31,813,239
Retained earnings	17,212,213	24,013,035
	51,877,522	55,856,001
Treasury stock, at cost, no shares and 801,889 shares as of June 30, 2014 and 2013, respectively	—	(1,019,840)
Total stockholders' equity	51,877,522	54,836,161

Total liabilities and stockholders' equity	$65,015,752	$66,556,296

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Operations

	Years Ended June 30,		
	2014	2013	2012
Revenues			
Delhi field	$16,908,666	$19,219,036	$15,143,770
Artificial lift technology	623,332	375,063	132,344
Other properties	141,510	1,755,821	2,685,924
Total revenues	17,673,508	21,349,920	17,962,038
Operating costs			
Artificial lift technology	609,221	390,238	124,703
Production costs - other properties	584,352	1,390,500	1,650,296
Depreciation, depletion and amortization	1,228,685	1,300,207	1,136,974
Accretion of discount on asset retirement obligations	41,626	72,312	77,505
General and administrative expenses*	8,388,291	7,495,309	6,143,286
Restructuring charges**	1,293,186	—	—
Total operating costs	12,145,361	10,648,566	9,132,764
Income from operations	5,528,147	10,701,354	8,829,274
Other			
Interest income	30,256	22,580	25,728
Interest (expense)	(69,092)	(65,745)	(21,950)
Income before income tax provision	5,489,311	10,658,189	8,833,052
Income tax provision	1,891,998	4,029,761	3,700,922
Net income attributable to the Company	3,597,313	6,628,428	5,132,130
Dividends on preferred stock	674,302	674,302	630,391
Net income attributable to common shareholders	$2,923,011	$5,954,126	$4,501,739
Earnings per common share			
Basic	$0.09	$0.21	$0.16
Diluted	$0.09	$0.19	$0.14
Weighted average number of common shares outstanding			
Basic	30,895,832	28,205,467	27,784,298
Diluted	32,564,067	31,975,131	31,609,929

* General and administrative expenses for the years ended June 30, 2014, 2013 and 2012 included non-cash stock-based compensation expense of $1,352,322, $1,531,745 and $1,475,995, respectively.

** Restructuring charges for the year ended June 30, 2014 included non-cash stock-based compensation expense of $376,365.

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Statements of Cash Flows

	Years Ended June 30,		
	2014	2013	2012
Cash flows from operating activities			
Net income attributable to the Company	$3,597,313	$6,628,428	$5,132,130
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,272,778	1,341,055	1,150,454
Stock-based compensation	1,352,322	1,531,745	1,475,995
Stock-based compensation related to restructuring	376,365	—	—
Accretion of discount on asset retirement obligations	41,626	72,312	77,505
Settlement of asset retirement obligations	(315,952)	(90,531)	(61,936)
Deferred income taxes	1,344,812	2,512,978	2,549,592
Deferred rent	(17,145)	(17,146)	(15,401)
Changes in operating assets and liabilities:			
Receivables from oil and natural gas sales	176,707	(289,506)	216,057
Receivables from income taxes and other	281,822	(189,813)	(64,194)
Due from joint interest partners	49,063	47,088	(10,046)
Prepaid expenses and other current assets	(480,899)	(33,121)	(165,581)
Accounts payable and accrued expenses	663,645	278,436	80,986
Income taxes payable	(233,548)	141,581	9,845
Net cash provided by operating activities	8,108,909	11,933,506	10,375,406
Cash flows from investing activities			
Proceeds from asset sales	542,347	3,479,976	799,610
Development of oil and natural gas properties	(966,931)	(4,163,080)	(3,291,921)
Acquisitions of oil and natural gas properties	(59,315)	(755,194)	(3,768,162)
Capital expenditures for other equipment	(312,890)	—	(61,176)
Advances to joint venture operating partner	—	—	(224,206)
Maturities of certificates of deposit	250,000	—	—
Other assets	(202,017)	(32,160)	(35,056)
Net cash used in investing activities	(748,806)	(1,470,458)	(6,580,911)
Cash flows from financing activities			
Proceeds from the exercise of stock options	3,252,801	70,719	—
Proceeds from issuance of preferred stock, net	—	—	6,930,535
Acquisitions of treasury stock	(1,655,251)	(137,818)	—
Common stock dividends paid	(9,723,833)	—	—
Preferred stock dividends paid	(674,302)	(674,302)	(630,391)
Deferred loan costs	(63,535)	(16,211)	(163,257)
Tax benefits related to stock-based compensation	509,096	794,569	249,728
Other	6,850	32	—
Net cash provided (used) by financing activities	(8,348,174)	36,989	6,386,615
Net increase (decrease) in cash and cash equivalents	(988,071)	10,500,037	10,181,110
Cash and cash equivalents, beginning of period	24,928,585	14,428,548	4,247,438
Cash and cash equivalents, end of period	$23,940,514	$24,928,585	$14,428,548

See accompanying notes to consolidated financial statements.

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Evolution Petroleum Corporation and Subsidiaries
Consolidated Statement of Changes in Stockholders' Equity
For the Years Ended June 30, 2014, 2013 and 2012

	Preferred		Common Stock					
	Shares	Par Value	Shares	Par Value	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
Balance, June 30, 2011	—	$—	27,612,916	$28,400	$20,761,209	$13,557,170	$(882,022)	$33,464,757
Issuance of preferred stock	317,319	317	—	—	7,932,658	—	—	7,932,975
Preferred stock issuance costs	—	—	—	—	(1,002,440)	—	—	(1,002,440)
Issuance of restricted common stock	—	—	196,106	196	(162)	—	—	34
Exercise of stock warrants	—	—	65,261	66	(66)	—	—	—
Exercise of stock options	—	—	7,941	8	(8)	—	—	—
Stock-based compensation	—	—	—	—	1,475,995	—	—	1,475,995
Tax benefits related to stock-based compensation	—	—	—	—	249,728	—	—	249,728
Net income	—	—	—	—	—	5,132,130	—	5,132,130
Preferred stock cash dividends	—	—	—	—	—	(630,391)	—	(630,391)
Balance, June 30, 2012	317,319	317	27,882,224	28,670	29,416,914	18,058,909	(882,022)	46,622,788
Issuance of restricted common stock	—	—	211,197	211	(179)	—	—	32
Exercise of stock options	—	—	529,237	529	70,190	—	—	70,719
Acquisitions of treasury stock	—	—	(13,689)	—	—	—	(137,818)	(137,818)
Stock-based compensation	—	—	—	—	1,531,745	—	—	1,531,745
Tax benefits related to stock-based compensation	—	—	—	—	794,569	—	—	794,569
Net income	—	—	—	—	—	6,628,428	—	6,628,428
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Balance, June 30, 2013	317,319	317	28,608,969	29,410	31,813,239	24,013,035	(1,019,840)	54,836,161
Issuance of restricted common stock	—	—	39,732	40	(40)	—	—	—
Exercise of warrants	—	—	905,391	905	(905)	—	—	—
	—	—	3,299,367	3,299	3,868,108	—	—	3,871,407

Exercise of stock options								
Forfeitures of restricted stock	—	—	(51,099)	(51)	51	—	—	—
Acquisitions of treasury stock	—	—	(186,714)	—	—	—	(2,273,857)	(2,273,857)
Retirements of treasury stock	—	—	—	(988)	(3,292,709)	—	3,293,697	—
Stock-based compensation *	—	—	—	—	1,728,687	—	—	1,728,687
Tax benefits related to stock-based compensation	—	—	—	—	509,096	—	—	509,096
Net income	—	—	—	—	—	3,597,313	—	3,597,313
Common stock cash dividends	—	—	—	—	—	(9,723,833)	—	(9,723,833)
Preferred stock cash dividends	—	—	—	—	—	(674,302)	—	(674,302)
Recovery of short swing profits	—	—	—	—	6,850	—	—	6,850
Balance, June 30, 2014	317,319	$317	32,615,646	$32,615	$34,632,377	$17,212,213	$—	$51,877,522

* Includes $376,365 of stock compensation reflected in restructuring charges.
See accompanying notes to consolidated financial statements.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Basis of Preparation

Nature of Operations. Evolution Petroleum Corporation ("EPM") and its subsidiaries (the "Company", "we", "our" or "us"), is an independent petroleum company headquartered in Houston, Texas and incorporated under the laws of the State of Nevada. We are engaged primarily in the development of incremental oil and gas reserves within known oil and gas resources for our shareholders and customers utilizing conventional and proprietary technology.

Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of EPM and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no impact on previously reported income or stockholders' equity.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include reserve quantities and estimated future cash flows associated with proved reserves, which significantly impact depletion expense and potential impairments of oil and natural gas properties, income taxes and the valuation of deferred tax assets, stock-based compensation and commitments and contingencies. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Note 2—Summary of Significant Accounting Policies

Cash and Cash Equivalents. We consider all highly liquid investments, with original maturities of 90 days or less when purchased, to be cash and cash equivalents.

Account Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date, uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We establish provisions for losses on accounts receivables if it is determined that collection of all or a part of an outstanding balance is not probable. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2014 and 2013, no allowance for doubtful accounts was considered necessary.

Oil and Natural Gas Properties. We use the full cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Excluded costs represent investments in unproved and unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the project is evaluated and proved reserves are established or impairment is determined. Excluded costs are reviewed at least quarterly to determine if impairment has occurred. The amount of any evaluated or impaired oil and natural gas properties is transferred to capitalized costs being amortized.

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the "Ceiling Test"). If the capitalized costs of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes , exceed the "Ceiling", this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent, and assuming continuation of existing economic conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. Our Ceiling Test did not result in an impairment of our oil and natural gas properties during the years ended June 30, 2014, 2013 or 2012.

Other Property and Equipment. Other property and equipment includes leasehold improvements, data processing and telecommunications equipment, office furniture and equipment, and oilfield service equipment related to our artificial lift technology operations. These items are recorded at cost and depreciated over expected lives of the individual assets or group of assets, which range from three to seven years. The assets are depreciated using the straight-line method, except for oilfield service equipment related to our artificial lift technology operations, which is depreciated using a method which approximates the timing and amounts of expected revenues from the contract. Repairs and maintenance costs are expensed in the period incurred.

Deferred Costs. The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in other assets on the Company's Consolidated Balance Sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

Asset Retirement Obligations. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred, with an associated increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The initial recognition or subsequent revision of asset retirement cost is considered a level 3 fair value measurement. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, certificates of deposit, accounts receivable, and accounts payable. The carrying amounts of these approximate fair value due to the highly liquid nature of these short-term instruments.

Stock-based Compensation. We record all share-based payment expense in our financial statements based on the estimated fair value of the award on the grant date. We use the Black-Scholes option-pricing model as the most appropriate fair-value method for our stock option awards. Restricted stock awards are valued using the market price of our common stock on the grant date. We record compensation cost, net of estimated forfeitures, for stock-based compensation awards over the requisite service period on a straight-line basis as the awards vest. As each award vests, an adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the vested awards.

Revenue Recognition - Oil and Gas. We recognize oil and natural gas revenue from our interests in producing wells at the time that title passes to the purchaser. As a result, we accrue revenues related to production sold for which we have not received payment.

Revenue Recognition - Artificial Lift Technology. Our artificial lift technology operations may generate revenues under several forms of operational or contractual arrangements. We have utilized the technology on wells that we develop and operate and on certain wells that we operate under farm-outs from other operators. In these cases, our revenues take the form of net sales of oil and gas production. We have also provided the technology to third parties under contractual arrangements that generate fees for the technology which are based on the net profits from oil and gas production. Under these contracts, we may be required to bear part or all of the incremental installation and capital costs for the technology. In other cases, we may be compensated for our technology through a fixed or variable fee per well, which does not require us to bear any net costs of installation or other capital costs. In the future, we may enter into licensing contracts which allow for the sale and installation of the technology by third parties to their customers or we may license the technology to larger organizations for use in specified geographic areas or on other broad terms. In all cases, we evaluate the substance of the contractual arrangement and recognize revenues over the life of the contract as the earnings process is determined to be complete. We likewise charge our costs, including both capital expenditures and operating expenses, to operating costs in a manner which either matches these costs to the timing of expected revenues, where appropriate, or charges these costs to the accounting period in which they were incurred where it is not appropriate to capitalize or defer them to match with revenues.

Depreciation, Depletion and Amortization. The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of DD&A, estimated future development costs and asset retirement costs not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized using the unit-of-production method over total proved reserves. Other property including, leasehold improvements, office and computer equipment and vehicles which are stated at original cost and depreciated using the straight-line method over the useful lives of the assets, which range from three to seven years.

Intangible Assets - Intellectual Property. The Company capitalizes the external costs, consisting primarily of legal costs, related to securing its patents, trademarks and other intellectual property. The costs of research, testing and development have been expensed as incurred. As of June 30, 2014, the cumulative costs capitalized in connection with our intellectual property was $346,520. The costs related to patents are amortized over the remaining life of the patent, whereas trademarks are perpetual and are not amortized. The remaining unamortized costs related to intellectual property as of June 30, 2014 was $319,470.

Income Taxes. We recognize deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management's assessment of available evidence if it is deemed more likely than not some or all of the deferred tax assets will not be realizable. We recognize a tax benefit from an uncertain position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position and will record the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement with a taxing authority. The Company classifies any interest and penalties associated with income taxes as income tax expense.

Earnings (loss) per share. Basic earnings (loss) per share ("EPS") is computed by dividing earnings or loss by the weighted-average number of common shares outstanding less any non-vested restricted common stock outstanding. The computation of diluted EPS is similar to the computation of basic EPS, except that the denominator is increased to include the number of additional common shares that would have been outstanding if potential dilutive common shares had been issued. Our potential dilutive common shares are our outstanding stock options, warrants, and non-vested restricted common stock. The dilutive effect of our potential dilutive common shares is reflected in diluted EPS by application of the treasury stock method. Under the treasury stock method, exercise of stock options and warrants shall be assumed at the beginning of the period (or at time of issuance, if later) and common shares shall be assumed to be issued; the proceeds from exercise shall be assumed to be used to purchase common stock at the average market price during the period; and the incremental shares (the difference between the number of shares assumed issued and the number of shares assumed purchased) shall be included in the denominator of the diluted EPS computation. Potential dilutive common shares are excluded from the computation if their effect is anti-dilutive. Including potential dilutive common shares in the denominator of a diluted EPS computation for continuing operations always will result in an anti-dilutive per-share amount when an entity has a loss from continuing operations and no potential dilutive common shares shall be included in the computation of diluted EPS when a loss from continuing operations exists.

Note 3—Recent Accounting Pronouncements

New Accounting Standards. We disclose the existence and potential effect of accounting standards issued but not yet adopted by us or recently adopted by us with respect to accounting standards that may have an impact on us in the future.

In July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) No. 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU applies to all entities that have unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists at the reporting date. U.S. GAAP does not include explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this ASU state that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except as follows. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The amendments in this ASU are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Company adopted this guidance on July 1, 2014, and does not expect that its adoption will have a material impact on our financial position, cash flows, or results of operations.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers: (Topic 606) to provide guidance on revenue recognition on contracts with customers to transfer goods or services or on contracts for the transfer of nonfinancial assets. ASU 2014-09 requires that revenue recognition on contracts with customers depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company does not believe its future adoption of this guidance will have a material effect on its financial position, cash flows, or results of operations.

Note 4—Property and Equipment

As of June 30, 2014 and June 30, 2013, our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2014	June 30, 2013
Oil and natural gas properties		
Property costs subject to amortization	$47,166,282	$42,772,184
Less: Accumulated depreciation, depletion, and amortization	(9,344,212)	(8,095,856)
Unproved properties not subject to amortization	—	4,112,704
Oil and natural gas properties, net	37,822,070	38,789,032
Other property and equipment		
Furniture, fixtures and office equipment, at cost	343,178	322,514
Artificial lift technology equipment, at cost	377,943	—
Less: Accumulated depreciation	(296,294)	(270,297)
Other property and equipment, net	$424,827	$52,217

As of June 30, 2014, all oil and gas property costs incurred by the Company were being amortized. At June 30, 2013, $4.1 million of our unproved properties were not subject to amortization and consisted of unevaluated acreage in the Mississippi Lime project in Oklahoma. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis. During the year ended June 30, 2014, we transferred $4.5 million of Mississippi Lime property cost to the full cost pool as initial quantities of hydrocarbon production were indicative of impairment.

In early November 2012, the Company sold its Wood well in the Giddings Field to EnerVest LLC and received net proceeds of $250,000 and the buyer's assumption of all abandonment liabilities.

On December 24, 2012, the Company closed the sale of a portion of its producing and non-producing properties and assets in Brazos, Burleson, Fayette, Lee and Grimes Counties, Texas to ASM Oil and Gas Company, Inc. ("ASM") for an adjusted purchase price of $2,804,976 and the buyer's assumption of all abandonment liabilities.

On May 1, 2013, the Company informed Orion Exploration Partners, LLC that it had elected to forego payment of the $1,209,197 remaining balance of its original purchase cost of leasehold in the Mississippi Lime formation in Kay County in Oklahoma. Accordingly, our joint venture interest in initial undrilled leasehold was reduced from 45% to 33.9% under the terms of the Agreement.

On June 14, 2013, the Company closed a second sale to ASM for producing and non-producing properties and assets in Brazos, Burleson, and Fayette Counties, Texas and received net proceeds of $425,000 and the buyer's assumption of all abandonment liabilities.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 1, 2013, we sold our producing assets and undeveloped reserves in the Lopez Field in South Texas in return for proceeds of $402,500 and the buyer's assumption of all abandonment liabilities.
The net proceeds from these sales, including the reduction of asset retirement obligations, were recognized as a reduction of the cost of oil and gas properties.
During the quarter ended June 30, 2014, we incurred $377,943 of costs related to the installation of our artificial lift technology on three wells for a third-party customer. Under the contract for these installations, we fund the majority of the incremental equipment and installation costs and will receive 25% of the net profits from production, as defined, for as long as the technology remains in the wells. We did not receive any revenues prior to June 30, 2014. We intend to depreciate or amortize the installation costs using a method and a life which approximates our expected net revenues from the wells.

Note 5 — Restructuring

On November 1, 2013, we undertook an initiative to refocus our business to GARP® development that resulted in adjustment of our workforce towards less emphasis on engineering and greater emphasis on sales and marketing. In exchange for severance and non-compete agreements with the terminated employees, we recorded a restructuring charge of approximately $1,332,186 representing $376,365 of stock-based compensation from the accelerated vesting of equity awards and $955,821 of severance compensation and benefits to be paid during the twelve months ended December 31, 2014. Our current estimate of remaining accrued restructuring charges as of June 30, 2014 is as follows:

Type of Cost	December 31, 2013	Payments	Adjustment to Cost	June 30, 2014
Salary continuation liability	$ 615,721	$ (307,860)	$—	$ 307,861
Incentive compensation costs	185,525	—	—	185,525
Other benefit costs and employer taxes	154,575	(78,549)	(39,000)	37,026
Accrued restructuring charges	$ 955,821	$ (386,409)	$ (39,000)	$ 530,412

Note 6 — Accrued Liabilities and Other

As of June 30, 2014 and June 30, 2013 our other current liabilities consisted of the following:

	June 30, 2014	June 30, 2013
Accrued incentive and other compensation	$ 1,358,653	$ 1,385,494
Accrued restructuring charges	530,412	—
Officer retirement costs	288,258	—
Asset retirement obligations due within one year	146,703	—
Accrued royalties	89,179	91,427
Accrued franchise taxes	87,575	94,116
Other accrued liabilities	57,224	59,066
Accrued liabilities and other	$ 2,558,004	$ 1,630,103

The officer retirement costs of $288,258 at June 30, 2014 reflects remaining payments to be made to the Company’s former Vice President and Chief Financial Officer under his February 14, 2014, retirement arrangement. In February the Company recorded a $608,000 charge including $204,000 of stock compensation from the accelerated vesting of his equity awards on February 15, 2014, together with $356,000 of salary and incentive compensation, and $48,000 of benefit payments to be paid during the twelve months ended February 14, 2015.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7—Asset Retirement Obligations

Our asset retirement obligations represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. The following is a reconciliation of the beginning and ending asset retirement obligation for the years ended June 30, 2014 and 2013:

	Years Ended	
	2014	2013
Asset retirement obligations—beginning of period	$615,551	$968,677
Liabilities incurred	—	60,143
Liabilities settled	(323,665)	(51,086)
Liabilities sold	(48,273)	(439,927)
Accretion of discount	41,626	72,312
Revisions to previous estimates	66,976	5,432
Less: current asset retirement obligations	(146,703)	—
Asset retirement obligations—end of period	$205,512	$615,551

Note 8—Stockholders' Equity

Common Stock

On August 31, 2011, the Board of Directors authorized the issuance of 161,861 shares of restricted common stock from the 2004 Stock Plan to all employees as a long-term incentive award. Total stock-based compensation expense of $1,029,436 related to the long-term incentive award will be recognized ratably over a period of four years as the restricted common stock vests. See Note 9 - Stock-Based Incentive Plan.

On December 5, 2011, a total of 34,245 shares of our restricted common stock were issued pursuant to the 2004 Stock Plan to five outside directors as part of their annual board compensation for calendar year 2012. The value of the shares issued was $249,955, based on the fair market value on the date of issuance. All issuances of our common stock were subject to vesting terms per individual stock agreements, which is one year for directors. See Note 9 - Stock-Based Incentive Plan.

On September 6, 2012, the Board of Directors authorized and the Company issued 154,227 shares of restricted common stock from the 2004 Stock Plan to all employees as a long-term incentive award. Total stock-based compensation expense of $1,223,020 related to the long-term incentive award will be recognized ratably over a four years period as the restricted common stock vests. See Note 9 - Stock-Based Incentive Plan.

On December 6, 2012, a total of 31,970 shares of our restricted common stock were issued pursuant to the 2004 Stock Plan to five outside directors as part of their annual board compensation for calendar year 2013. The value of the shares issued was $249,973 based on the fair market value on the date of issuance. All issuances of our common stock were subject to vesting terms per individual stock agreements, which is one year for directors. See Note 9 - Stock-Based Incentive Plan.

On December 5, 2013, a total of 16,476 shares of our restricted common stock were issued pursuant to the 2004 Stock Plan to five outside directors as part of their annual board compensation for calendar year 2014. The value of the shares issued was $200,019 based on the fair market value on the date of issuance. All issuances of our common stock were subject to vesting terms per individual stock agreements, which is one year for directors. See Note 9 - Stock-Based Incentive Plan.

During the year ended June 30, 2014, we issued (i) 1,568,832 shares of our common stock upon the exercise of incentive stock options (ISOs), receiving cash proceeds totaling $3,252,801, and (ii) 2,635,696 of our common shares upon cashless exercises of nonqualified stock options ("NQSOs") and incentive warrants, all being exercised on a net basis, except for 50,956 of previously acquired shares owned by option holders that were swapped in payment of the exercise price. The weighted average cost of these swapped shares was $12.14.

In fiscal 2014, we retired 801,889 shares of treasury stock acquired in previous fiscal years at a cost of $1,019,840 and 186,714 treasury shares acquired during fiscal 2014 from employees and directors at an average cost of $12.18 per share or $2,273,857. The shares acquired in 2014 were received in satisfaction of payroll tax liabilities from the exercise of stock options and vesting of restricted stock (requiring cash outlays by us) and 50,956 shares were received from option holders in cashless stock option exercises, using stock previously owned by the option holder.

During the year ended June 30, 2014, as the result of a common stock dividend policy approved in November 2013 by the Board of Directors, we paid three quarterly cash dividends to our common shareholders, totaling $9,723,833, from retained earnings. The cash dividends were paid at a quarterly rate of $0.10 per common share. The large tax deductions related to the fiscal 2014 exercises of stock options and warrants result in a deficit in our current year earnings and profits, as defined for tax purposes, and accordingly, the cash dividends on common shares paid in fiscal 2014 will be treated for tax purposes as a return of capital and not as dividend income to the shareholders.

Since the tax benefits related to stock-based compensation created by fiscal year 2014 exercises of warrants and NQSOs result in a deficit in current year earnings and profits, as defined for tax purposes, all cash dividends on common shares paid in fiscal 2014 will be treated for tax purposes as a return of capital and not as dividend income to the shareholders.

Recovery of Stockholder Short Swing Profit

In September 2013, an executive officer of the Company paid $6,850 to the Company, representing the disgorgement of short swing profits under Section 16(b) under the Exchange Act. The amount was recorded as additional paid-in capital.

Series A Cumulative Perpetual Preferred Stock

During the year ended June 30, 2012, we sold 317,319 shares of our 8.5% Series A Cumulative (perpetual) Preferred Stock at a weighted average sales price of $23.80 per share, with a liquidation preference of $25.00 per share. All shares were underwritten or sold through McNicoll Lewis & Vlak LLC (MLV), 220,000 of which were sold in an underwritten public offering and 97,319 shares of which were sold under an at-the-market sales agreement ("ATM"), providing aggregate net proceeds of $6,930,535 after market discounts, underwriting fees, legal and other expenses of the offerings. The Series A Cumulative Preferred Stock cannot be converted into our common stock and there are no sinking fund or redemption rights available to holders thereof. Optional redemption can be made by us at any time after July 1, 2014 for the stated liquidation value of $25.00 per share plus accrued dividends. With respect to dividend rights and rights upon our liquidation, winding-up or dissolution, the Series A Preferred Stock ranks senior to our common shareholders, but subordinate to any of our existing and future debt. Dividends on the Series A Cumulative Preferred Stock accrue and accumulate at a fixed rate of 8.5% per annum on the $25.00 per share liquidation preference, payable monthly at $0.177083 per share, as, if and when declared by our Board of Directors.

We paid dividends of $674,302, $674,302, and $630,391 to holders of our Series A Preferred Stock during the years ended June 30, 2014, 2013 and 2012 , respectively. The large tax deductions related to the fiscal 2014 exercises of stock options and warrants result in a deficit in our current year earnings and profits, as defined for tax purposes, and accordingly, the cash dividends on the Series A Preferred Stock paid in fiscal 2014 will be treated for tax purposes as a return of capital and not as dividend income to the shareholders.

Note 9—Stock-Based Incentive Plan

We have granted option awards to purchase common stock (the "Stock Options"), restricted common stock awards ("Restricted Stock"), and/or unrestricted fully vested common stock, to employees, directors, and consultants of the Company under the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the "Plan"). The Plan authorized the issuance of 6,500,000 shares of common stock and 812,281 shares remain available for grant as of June 30, 2014.

Stock Options and Incentive Warrants

Non-cash stock-based compensation expense related to Stock Options for the years ended June 30, 2014, 2013 and 2012 was $0, $26,274 and $327,776, respectively. As of August 31, 2012, all compensation costs attributable to Stock Options had been recognized. No Stock Options have been granted since August 2008.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following summary presents information regarding outstanding Stock Options as of June 30, 2014, and the changes during the fiscal year:

	Number of Stock Options	Weighted Average Exercise Price	Aggregate Intrinsic Value(1)	Weighted Average Remaining Contractual Term (in years)
Stock Options and Incentive Warrants outstanding at June 30, 2013	4,822,820	$1.99		
Granted	—	—		
Exercised	(4,644,759)	$1.99		
Canceled or forfeited	—	—		
Expired	—	—		
Stock Options and Incentive Warrants outstanding at June 30, 2014	178,061	$2.08	$1,580,075	1.75
Vested or expected to vest at June 30, 2014	178,061	$2.08	$1,580,075	1.75
Exercisable at June 30, 2014	178,061	$2.08	$1,580,075	1.75

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($10.95 as of June 30, 2014) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

For the year ended June 30, 2014, there were 4,644,759 Stock Options and Incentive Warrants exercised with an aggregate intrinsic value of $47,504,114. For the year ended June 30, 2013, there were 550,000 Stock Options exercised, with an aggregate intrinsic value of $5,233,480. For the year ended June 30, 2012, there were 20,000 Stock Options exercised with an aggregate intrinsic value of $54,000.

During the years ended June 30, 2014, 2013, and 2012, there were 0, 18,922, and 154,955 Stock Options and Incentive Warrants that vested with a total grant date fair value of $0, $46,359, and $336,252, respectively.

Restricted Stock

For the years ended June 30, 2014, 2013, and 2012, we recognized stock-based compensation expense related to Restricted Stock grants of $1,728,687, $1,505,471, and $1,148,219, respectively. Of total stock compensation expense for the year end June 30, 2014, $376,365 was incurred in connection our second quarter restructuring. See Note 5 - Restructuring.

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2014:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested at June 30, 2013	386,599	$6.65
Granted	39,732	$12.58
Vested	(277,198)	$6.48
Forfeited	(9,066)	$5.98
Unvested at June 30, 2014	140,067	$8.70

During the years ended June 30, 2014, 2013, and 2012, there were 277,198, 277,198, and 239,195 shares of Restricted Stock that vested with a total grant date fair value of $1,796,243, $1,427,570, and $1,078,769, respectively.

At June 30, 2014, unrecognized stock compensation expense related to Restricted Stock grants totaled $997,403. Such unrecognized expense will be recognized over a weighted average remaining service period of 2.1 years.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10—Supplemental Disclosure of Cash Flow Information
Our supplemental disclosures of cash flow information for the years ended June 30, 2014, 2013, and 2012 are as follows:

	June 30, 2014	2013	2012
Income taxes paid	$755,941	$699,874	$895,000
Non-cash transactions:			
Change in accounts payable used to acquire property and equipment	$(183,766)	$(1,535,322)	$1,761,633
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	$66,976	$65,575	$93,522
Previously acquired Company shares swapped by holders to pay stock option exercise price	$618,606	$—	$—

Note 11—Income Taxes
We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions.
There were no unrecognized tax benefits nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2014, 2013 and 2012. We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's tax returns are open to audit under the statute of limitations for the years ending June 30, 2010 through June 30, 2013 for federal tax purposes and for the years ended June 30, 2010 through June 30, 2013 for state tax purposes.
The components of our income tax provision (benefit) are as follows:

	June 30, 2014	June 30, 2013	June 30, 2012
Current:			
Federal	$386,018	$857,480	$309,632
State	161,168	659,303	841,698
Total current income tax provision	547,186	1,516,783	1,151,330
Deferred:			
Federal	1,319,727	2,546,495	2,542,662
State	25,085	(33,517)	6,930
Total deferred income tax provision	1,344,812	2,512,978	2,549,592
Total income tax provision	$1,891,998	$4,029,761	$3,700,922

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate, currently 34%, to the income tax provision in our financial statements. The effective tax rate for all years is in excess of the statutory rate as a result of state income taxes, primarily in the state of Louisiana, with smaller adjustments related to stock-based compensation and other permanent differences.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	June 30, 2014	June 30, 2013	June 30, 2012
Income tax provision (benefit) computed at the statutory federal rate:	$1,866,366	$3,623,784	$3,003,238
Reconciling items:			
State income taxes, net of federal tax benefit	189,081	413,019	560,095
Permanent differences related to stock-based compensation	(155,817)	8,933	83,115
Expiring NOLs related to 2004 reverse merger	—	600,964	4,348,495
Deferred tax asset valuation adjustment	—	(600,964)	(4,348,495)
Other permanent differences	(7,632)	(15,975)	54,474
Income tax provision	$1,891,998	$4,029,761	$3,700,922

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Deferred tax assets and liabilities are classified as either current or noncurrent on the balance sheet based on the classification of the related asset or liability for financial reporting purposes. Deferred tax assets and liabilities not related to specific assets or liabilities on the financial statements are classified according the expected reversal date of the temporary difference or the expected utilization date for tax attribute carryforwards. The change in the NOL is primarily due to expiring NOLs related to the 2004 reverse merger as well as utilization of NOL to offset potential current year taxable income. The components of our deferred taxes are detailed in the table below:

	June 30, 2014	June 30, 2013	June 30, 2012
Deferred tax assets:			
Non-qualified stock-based compensation	$134,469	$774,673	$774,720
Net operating loss carry-forwards	427,249	427,249	1,336,769
AMT credit carry-forward*	701,254	502,466	714,571
Other	165,775	28,170	29,929
Gross deferred tax assets	1,428,747	1,732,558	2,855,989
Valuation allowance	(292,446)	(292,446)	(893,410)
Total deferred tax assets	1,136,301	1,440,112	1,962,579
Deferred tax liability:			
Oil and natural gas properties	(10,873,949)	(9,832,948)	(7,842,437)
Total deferred tax liability	(10,873,949)	(9,832,948)	(7,842,437)
Net deferred tax liability	$(9,737,648)	$(8,392,836)	$(5,879,858)

* Total AMT credit carry-forward is $824,087. Our net deferred tax liability does not include $122,833 of AMT credit carry-forward associated with the tax benefit related to stock-based compensation.

As of June 30, 2014, we have a federal tax loss carryforward of approximately $28.9 million, consisting of $27.6 million of tax deductions in excess of book deductions related to the exercise of stock options and incentive warrants in fiscal 2014, and $1.3 million of remaining tax loss carryforwards that we acquired through the reverse merger in May 2004. The majority of the tax loss carryforwards from the reverse merger have expired without being utilized. We will be able to utilize a maximum of $0.4 million of these carryforwards in equal annual amounts through 2023 and the balance is not able to be utilized based on the provisions of IRC Section 382. We have recorded a valuation allowance for the portion of our net operating loss that is limited by IRC Section 382.

The tax loss carry-forward of $27.6 million and future tax benefits resulting from the fiscal 2014 exercise of 4.6 million of our 4.8 million outstanding stock options and incentive warrants will not affect our future tax provision for financial

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reporting purposes, nor are we able to recognize a deferred tax asset for these future benefits. When we receive these tax benefits as a reduction of future cash taxes that would otherwise be payable, we will recognize that benefit as an increase in additional paid in capital.

In addition, as of June 30, 2014, the Company has an estimated carryforward of percentage depletion in excess of basis of approximately $9.1 million. These future deductions are limited to 65% of taxable income in any period.

Note 12—Related Party Transactions

On June 30, 2011, we entered into a Technology Assignment Agreement with the Company's Vice President of Operations to acquire exclusive, perpetual, non-cancelable rights to the patented GARP® technology he developed while employed by the Company. Under the agreement, he is paid a fee when the technology is employed. For the years ended June 30, 2014, 2013 and 2012, we made payments of $10,113, $10,113 and $20,000, respectively, under the agreement.

Note 13—Net Income Per Share

The following table sets forth the computation of basic and diluted net income per share:

	June 30, 2014	2013	2012
Numerator			
Net income attributable to common shareholders	$2,923,011	$5,954,126	$4,501,739
Denominator			
Weighted average number of common shares—Basic	30,895,832	28,205,467	27,784,298
Effect of dilutive securities:			
Common stock warrants issued in connection with equity and financing transactions	—	878	63,319
Stock Options and Incentive Warrants	1,668,235	3,768,786	3,762,312
Total weighted average dilutive securities	1,668,235	3,769,664	3,825,631
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	32,564,067	31,975,131	31,609,929
Net income per common share—Basic	$0.09	$0.21	$0.16
Net income per common share—Diluted	$0.09	$0.19	$0.14

Outstanding potentially dilutive securities as of June 30, 2014 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2014
Common stock warrants issued in connection with equity and financing transactions	$—	—
Stock Options	$2.08	178,061
Total	$2.08	178,061

Outstanding potentially dilutive securities as of June 30, 2013 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2013
Common stock warrants issued in connection with equity and financing transactions	$2.50	1,165
Stock Options and Incentive Warrants	$1.99	4,822,820
Total	$1.99	4,823,985

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
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Outstanding potentially dilutive securities as of June 30, 2012 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2012
Common stock warrants issued in connection with equity and financing transactions	$2.50	1,165
Stock Options and Incentive Warrants	$1.83	5,485,820
Total	$1.83	5,486,985

Note 14—Unsecured Revolving Credit Agreement

On February 29, 2012, Evolution Petroleum Corporation entered into a Credit Agreement (the "Credit Agreement") with Texas Capital Bank, N.A. (the "Lender"). The Credit Agreement provides the Company with a revolving credit facility (the "facility") in an amount up to $50,000,000 with availability governed by an Initial Borrowing Base of $5,000,000. A portion of the facility not in excess of $1,000,000 is available for the issuance of letters of credit. The facility is unsecured and has a term of four years. The Company's subsidiaries guarantee the Company's obligations under the facility. The proceeds of any loans under the facility are to be used by the Company for the acquisition and development of oil and gas properties, as defined in the facility, the issuance of letters of credit, and for working capital and general corporate purposes.

Semi-annually, the borrowing base and a monthly reduction amount are re-determined from reserve reports. Requests by the Company to increase the $5,000,000 initial amount are subject to the Lender's credit approval process, and are also limited to 25% of the value our oil and gas properties, as defined.

At the Company's option, borrowings under the facility bear interest at a rate of either (i) an Adjusted LIBOR rate (LIBOR rate divided by the remainder of 1 less the Lender's Regulation D reserve requirement), or (ii) an adjusted Base Rate equal to the greater of the Lender's prime rate or the sum of 0.50% plus the Federal Fund Rate. A maximum of three LIBOR based loans can be outstanding at any time. Allowed loan interest periods are one, two, three and six months. LIBOR interest is payable at the end of the interest period except for six-month loans for which accrued interest is payable at three months and at end of term. Base Rate interest is payable monthly. Letters of credit bear fees of 3.5% per annum rate applied to the principal amount and are due when transacted. The maximum term of letters of credit is one year.

A commitment fee of 0.50% per annum accrues on unutilized availability and is payable quarterly. The Company is responsible for certain administrative expenses of the Lender over the life of the Credit Agreement as well as $50,000 in loan costs incurred upon closing.

The Credit Agreement also contains financial covenants including a requirement that the Company maintain a current ratio of not less than 1.5 to 1; a ratio of total funded Indebtedness to EBITDA of not more than 2.5 to 1, and a ratio of EBITDA to interest expense of not less than 3 to 1. The agreement specifies certain customary covenants, including restrictions on the Company and its subsidiaries from pledging their assets, incurring defined Indebtedness outside of the facility other that permitted indebtedness, and it restricts certain asset sales. Payments of dividends for the Series A Preferred are only restricted by the EBITDA to interest coverage ratio, wherein such dividends are a 1X deduction from EBITDA (as opposed to a 3:1 requirement if dividends were treated as interest expense). The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the Lender may declare any amounts outstanding under the Credit Agreement to be immediately due and payable.

As of June 30, 2014 and 2013, the Company had no borrowings and no outstanding letters of credit issued under the facility, resulting in an available borrowing base capacity of $5,000,000, and we are in compliance with all the covenants of the Credit Agreement. During the year the Lender waived the provisions of the Credit Agreement pertaining to the past payments of cash dividends on our common stock, and the Credit Agreement was amended to permit the payment of cash dividends on common stock in the future if no borrowings are outstanding at the time of such payment.

In connection with this agreement the Company incurred $179,468 of debt issuance costs, which have been capitalized in Other Assets and are being amortized on a straight-line basis over the term of the agreement. The unamortized balance in debt issuance costs related to the Credit Agreement was $81,047 as of June 30, 2014. The Company is in discussions with the Lender to replace the unsecured Credit Agreement with an expanded secured facility. As of June 30, 2014, the Company had incurred approximately $63,535 in legal and title costs related to this proposed agreement, which are also capitalized in Other Assets.

Note 15—Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdiction in which we operate. We disclose such matters if we believe it is reasonably possible that a future event or events will confirm a loss through impairment of an asset or the incurrence of a liability. We accrue a loss if we believe it is probable that a future event or events will confirm a loss and we can reasonably estimate such loss and we do not accrue future legal costs related to that loss. Furthermore, we will disclose any matter that is unasserted if we consider it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable. We expense legal defense costs as they are incurred.

The Company and its wholly owned subsidiary are defendants in a lawsuit brought by John C. McCarthy et. al in the Fifth District Court of Richland Parish, Louisiana in July 2011. The plaintiffs alleged, among other claims, that we fraudulently and wrongfully purchased plaintiffs' income royalty rights in the Delhi Field Unit in the Holt-Bryant Reservoir in May 2006. On March 29, 2012, the Fifth District Court dismissed the case against the Company and our wholly owned subsidiary NGS Sub Corp. The Court found that plaintiffs had "no cause of action" under Louisiana law, assuming that the Plaintiff's claims were valid on their face. Plaintiffs filed an appeal and the Louisiana Second Circuit Court of Appeal affirmed the dismissal, but allowed the plaintiffs to amend their petition to state a different possible cause of action. The plaintiffs amended their claim and re-filed with the district court. The plaintiffs are seeking cancellation of the lease and monetary damages. We subsequently filed a second motion pleading "no cause of action," with which the district court again agreed and dismissed the plaintiffs' case on September 23, 2013. Plaintiffs again filed an appeal in November 2013.

On October 14, 2013, a settlement agreement was executed in the lawsuit filed by Frederick M. Garcia and Lydia Garcia, et. al and the lawsuit was dismissed with prejudice on November 5, 2013. As previously reported, on July 26, 2012, we agreed to settle a lawsuit filed by Frederick M. Garcia and Lydia Garcia in December 2010 in Duval County, Texas, in which the plaintiffs alleged failure to maintain the lease beyond its primary term due to no production. Although we believed that the claims were without merit, we chose to settle for $67,000 in return for an extension of the primary term of the lease, an amount less than our expected cost to prevail in court through summary judgment.

As previously reported, on August 23, 2012, we and our wholly-owned subsidiary, NGS Sub Corp., and Robert S. Herlin, our President and Chief Executive Officer, were served with a lawsuit filed in federal court by James H. and Kristy S. Jones (the "Jones lawsuit") in the Western District Court of the Monroe Division, Louisiana. The plaintiffs allege primarily that we (defendants) wrongfully purchased the plaintiffs' 0.048119 overriding royalty interest in the Delhi Unit in January 2006 by failing to divulge the existence of an alleged previous agreement to develop the Delhi Field for EOR. The plaintiffs are seeking rescission of the assignment of the overriding royalty interest and monetary damages. We believe that the claims are without merit and are not timely, and we are vigorously defending against the claims. We filed a motion to dismiss for failure to state a claim under Federal Rule of Civil Procedure 12(b) (6) on April 1, 2013. On September 17, 2013, the federal court in the Western District Court of the Monroe Division, Louisiana, dismissed a portion of the claims and allowed the plaintiffs to pursue the remaining portion of the claims. Our motion to dismiss was for lack of cause of action, assuming that the plaintiff's claims were valid on their face. On September 25, 2013, plaintiff Jones filed a motion to alter or amend the September 17, 2013 judgment. On December 27, 2013, the court denied said plaintiffs' motion, and on January 21, 2014, we filed a motion to reconsider the nondismissal of the remaining claims, which was denied. Counsel has advised us that, based on information developed to date, the risk of loss in this matter is remote.

On December 13, 2013, we and our wholly-owned subsidiaries, Tertiaire Resources Company and NGS Sub. Corp., filed a lawsuit in the 133rd Judicial District Court of Harris County, Texas, against Denbury Onshore, LLC ("Denbury") alleging breaches of certain 2006 agreements between the parties regarding the Delhi Field in Richland Parish, Louisiana. The specific allegations include improperly charging the payout account for capital expenditures and costs of capital, failure to adhere to preferential rights to participate in acquisitions within the defined area of mutual interest, breach of the promises to assume environmental liabilities and fully indemnify us from such costs, and other breaches. We are seeking declaration of the validity of the 2006 agreements and recovery of damages and attorneys' fees. Denbury subsequently filed counterclaims, including the assertion that we owed Denbury additional revenue interests pursuant to the 2006 agreements and that our transfer of our reversionary working interest from our wholly owned subsidiary to our parent corporation and subsequently to another wholly owned subsidiary breached their preferential right to purchase. We have denied their counterclaims as being without merit and not timely.

On December 3, 2013, our wholly owned subsidiary, NGS Sub. Corp., was served with a lawsuit filed in the 8th Judicial District Court of Winn Parish, Louisiana by Cecil M. Brooks, a resident of Louisiana, alleging that a former subsidiary of NGS Sub. Corp. improperly disposed of water from an off-lease well into a well located on the plaintiff's land in Winn Parish in 2006. The plaintiff is requesting monetary damages and other relief. NGS Sub. Corp. disposed of the property in question along with its ownership of the subsidiary in 2008 to a third party. We have denied the claims.

Lease Commitments. We have a non-cancelable operating lease for office space that expires on August 1, 2016. Future minimum lease commitments as of June 30, 2014 under this operating lease are as follows:

For the year ended June 30,	
2015	$159,011
2016	159,011
2017	13,251
Total	$331,273

Rent expense for the years ended June 30, 2014, 2013, and 2012 was $174,229, $147,233, and $147,233, respectively.

Employment Contracts. We have entered into employment agreements with two of the Company's senior executives. The employment contracts provide for severance payments in the event of termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, as defined. The agreements provide for the payment of base pay and certain medical and disability benefits for periods ranging form 6 months to 1 year after termination. The total contingent obligations under the employment contracts as of June 30, 2014 was approximately $591,000.

Note 16—Concentrations of Credit Risk

Major Customers. We market all of our oil and natural gas production from the properties we operate. The majority of our operated gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-based prices. The following table identifies customers from whom we derived 10 percent or more our net oil and natural gas revenues during the years ended June 30, 2014, 2013, and 2012. Based on the current demand for oil and natural gas and availability of other customers, we do not believe the loss of any of these customers would have a significant effect on our operations or financial condition.

	Year Ended June 30,		
Customer	2014	2013	2012
Plains Marketing L.P. (includes Delhi production)	96%	90%	84%
Enterprise Crude Oil LLC	2%	4%	7%
Flint Hills	1%	2%	1%
ETC Texas Pipeline, LTD.	1%	—%	3%
All others	—%	4%	5%
Total	100%	100%	100%

Accounts Receivable. Substantially all of our accounts receivable result from uncollateralized oil and natural gas sales to third parties in the oil and natural gas industry. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Cash and Cash Equivalents and Certificates of Deposit. We are subject to concentrations of credit risk with respect to our cash and cash equivalents, which we attempt to minimize by maintaining our cash and cash equivalents in high quality money market funds. At times, cash balances may exceed limits federally insured by the Federal Deposit Insurance Corporation ("FDIC"). Our certificates of deposit are below or at the maximum federally insured limit set by the FDIC.

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Note 17—Retirement Plan

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all full-time employees. We currently match 100% of employees' contributions to the plan, to a maximum of the first 6% of each participant's compensation, with Company contributions fully vested when made. Our matching contributions to the Savings Plan totaled $116,873, $89,810, and $84,738 for the years ended June 30, 2014, 2013, and 2012, respectively.

Note 18—Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)

Costs incurred for oil and natural gas property acquisition, exploration and development activities

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Exploration and development costs also include amounts incurred due to the recognition of asset retirement obligations, of $66,976, $65,575, and $93,522, during the years ended June 30, 2014, 2013, and 2012 , respectively.

	For the Years Ended June 30,		
	2014	2013	2012
Oil and natural gas activities			
Property acquisition costs:			
Proved property	$—	$26,449	$115,637
Unproved property	47,344	195,599	5,544,217
Exploration costs	757,423	4,356,640	3,016,924
Development costs	18,566	79,035	238,463
Total costs incurred for oil and natural gas activities	$823,333	$4,657,723	$8,915,241

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers. Reserve volumes and values were determined under the method prescribed by the SEC for our fiscal years ended June 30, 2014, 2013, and 2012, which requires the application of the previous 12 months unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce.

Proved oil and natural gas reserves are estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

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EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimated quantities of proved oil and natural gas reserves and changes in quantities of proved developed and undeveloped reserves for each of the periods indicated were as follows:

	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2011	11,567,846	712,300	9,403,899	13,847,462
Revisions of previous estimates	84,219	(212,677)	(1,295,893)	(344,440)
Improved recovery, extensions and discoveries	137,634	5,461	18,925	146,249
Production (sales volumes)	(151,081)	(12,611)	(266,775)	(208,155)
June 30, 2012	11,638,618	492,473	7,860,156	13,441,116
Revisions of previous estimates (a)	1,826,053	975,515	27,679	2,806,181
Sales of minerals in place	(485,536)	(480,832)	(7,726,032)	(2,254,038)
Production (sales volumes)	(196,380)	(7,271)	(139,006)	(226,819)
June 30, 2013	12,782,755	979,885	22,797	13,766,440
Revisions of previous estimates (b)	(1,919,052)	1,269,588	2,412,677	(247,350)
Improved recovery, extensions and discoveries	17,146	32,731	498,044	132,884
Sales of minerals in place	(184,722)	—	—	(184,722)
Production (sales volumes)	(169,783)	(3,516)	(26,655)	(177,742)
June 30, 2014	10,526,344	2,278,688	2,906,863	13,289,510
Proved developed reserves:				
June 30, 2011	4,986,337	100,900	1,543,401	5,344,471
June 30, 2012	7,670,934	111,978	1,499,382	8,032,809
June 30, 2013	10,077,522	8,539	22,797	10,089,861
June 30, 2014	7,858,224	32,164	481,042	7,970,562

(a) A significant upward reserve revision occurred in the Delhi Field during fiscal 2013 as a result of (1) revised geological maps based on production results and acquired seismic data, (2) inclusion of an additional reservoir with similar features, production history and suitability for EOR, and (3) inclusion of natural gas processing at Delhi.

(b) Significant reserve revisions occurred in the Delhi Field during fiscal 2014. As a result of an adverse fluid release event in the Field, certain oil reserves were reclassified from proved to an unproved category based on the operator's decision to defer CO_2 injections in certain parts of the Field. There was a positive revision to estimated proved reserves of natural gas liquids and natural gas as a result of an improved design for the gas plant in the Delhi Field. The plant is expected to significantly increase recoveries of these products, particularly natural gas, which was not previously planned to be extracted from the injection volumes.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by ASC 932, Disclosures about Oil and Gas Producing Activities ("ASC 932"). ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our proved oil and natural gas reserves assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the

Company's proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of our proved reserves.

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2014, 2013, and 2012 are as follows:

	For the Years Ended June 30,		
	2014	2013	2012
Future cash inflows	$1,193,515,075	$1,436,980,607	$1,355,686,188
Future production costs and severance taxes	(475,387,931)	(510,902,614)	(458,716,938)
Future development costs	(46,154,178)	(60,742,406)	(38,458,724)
Future income tax expenses	(195,581,510)	(275,113,560)	(296,703,838)
Future net cash flows	476,391,456	590,222,027	561,806,688
10% annual discount for estimated timing of cash flows	(250,313,784)	(283,001,328)	(278,209,195)
Standardized measure of discounted future net cash flows	$226,077,672	$307,220,699	$283,597,493

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12 months unweighted arithmetic average first-day-of-the-month commodity prices for each year and reflect adjustments for lease quality, transportation fees, energy content and regional price differentials.

	Year Ended June 30,					
	2014		2013		2012	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$100.37	$4.10	$91.51	$3.44	$95.67	$3.15

The NGL price utilized for future cash inflows was based on the historical price received.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved crude oil, natural gas liquids, and natural gas reserves is as follows:

	For the Years Ended June 30,		
	2014	2013	2012
Balance, beginning of year	$307,220,699	$283,597,493	$228,447,954
Net changes in sales prices and production costs related to future production	(73,439,526)	(35,184,725)	76,942,613
Changes in estimated future development costs	9,848,614	(566,125)	6,340,123
Sales of oil and gas produced during the period, net of production costs	(16,479,934)	(19,569,182)	(16,187,039)
Net change due to extensions, discoveries, and improved recovery	775,574	—	1,606,122
Net change due to revisions in quantity estimates	(23,757,788)	64,817,544	(11,975,496)
Net change due to sales of minerals in place	(3,150,277)	(34,119,027)	—
Development costs incurred during the period	—	747,656	(2,639,398)
Accretion of discount	45,896,187	41,678,733	22,568,868
Net change in discounted income taxes	58,073,450	10,175,957	(15,026,628)
Net changes in timing of production and other (a)	(78,909,327)	(4,357,625)	(6,479,626)
Balance, end of year	$226,077,672	$307,220,699	$283,597,493

(a) The operator has expressed current plans to produce the Delhi Field at lower production rates. The decision to produce these reserves at lower rates over a longer period of time did not materially change the total quantities expected to be recovered, but resulted in a significant reduction in the discounted value of these reserves as of June 30, 2014.

Note 19—Fair Value Measurement

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

The three levels are defined as follows:

Level 1—Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2—Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3—Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair Value of Financial Instruments. The Company's other financial instruments consist of cash and cash equivalents, certificates of deposit, receivables and payables. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

Other Fair Value Measurements. The initial measurement and any subsequent revision of asset retirement obligations at fair value are calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, surface restoration and reserve lives. Subsequent to initial recognition, revisions to estimated asset retirement obligations are made when changes occur for input values, which the Company reviews quarterly.

Note 20—Selected Quarterly Financial Data (Unaudited)

The following table presents summarized quarterly financial information for the years ended June 30, 2014 and 2013:

2014	First	Second (1)	Third (2)	Fourth
Revenues	$4,633,699	$4,392,289	$4,337,006	$4,310,514
Operating income (loss)	1,963,897	(158,095)	1,357,534	2,364,811
Net income (loss) available to common shareholders	$1,303,876	$(577,459)	$755,125	$1,441,469
Basic net income (loss) per share	$0.05	$(0.02)	$0.02	$0.04
Diluted net income (loss) per share	$0.04	$(0.02)	$0.02	$0.04

(1) Reflects a $1.3 million restructuring charge and $0.8 million of non-recurring expenses primarily associated with the exercise of 4.0 million of 4.8 million of previously outstanding stock options and warrants.

(2) Includes $608,000 of non-recurring expenses related to the retirement of an officer of the Company.

2013	First	Second	Third	Fourth (1)
Revenues	$4,291,546	$5,648,058	$6,010,567	$5,399,749
Operating income	$1,930,556	$3,024,721	$3,394,531	$2,351,546
Net income available to common shareholders	$990,951	$1,790,696	$2,228,467	$944,012
Basic net income per share	$0.04	$0.06	$0.08	$0.03
Diluted net income per share	$0.03	$0.06	$0.07	$0.03

(1) The tax provision for fiscal 2013 reflects a higher effective tax rate compared to the estimated annual effective rate at March 31, 2013. The March effective rate included the favorable effect depletion in excess of basis and was based on the Company's estimate of taxable ordinary income at that time. In contrast to the March forecast, actual taxable

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income for fiscal 2013 was lower due to a taxable loss on the sale of assets in June 2013 and lower than expected book income due to $0.6 million of lower Delhi Field revenue and $0.4 million of higher general and administrative expense, primarily attributable to an increase in accrued bonus, shelf registration costs and an engineering study.

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to this Company's management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely decisions regarding required disclosure.

As required by Securities and Exchange Commission Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company's internal control over financial reporting based on criteria established in the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2014.

The effectiveness of our internal control over financial reporting at June 30, 2014 has been audited by Hein & Associates LLP, the independent registered public accounting firm that also audited our financial statements. Their report is included on page 41 in Item 8. "Financial Statements" of this Annual Report on form 10-K under the heading Report of Independent Registered Public Accounting Firm on internal control over financial reporting.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the fourth quarter ended June 30, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers And Corporate Governance

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2014 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2014 fiscal year.

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

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2014 fiscal year.

Item 13. Certain Relationships and Related Transactions, Director Independence

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2014 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2014 fiscal year.

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PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets
Consolidated Statements of Operations
Consolidated Statements of Cash Flows
Consolidated Statements of Stockholders' Equity
Notes to the Consolidated Financial Statements

2. Financial Statements Schedules and supplementary information required to be submitted:

None.

3. Exhibits

A list of the exhibits filed or furnished with this report on Form 10-K (or incorporated by reference to exhibits previously filed or furnished by us) is provided in the Exhibit Index of this report. Those exhibits incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Otherwise, the exhibits are filed herewith.

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GLOSSARY OF SELECTED PETROLEUM TERMS

The following abbreviations and definitions are terms commonly used in the crude oil and natural gas industry and throughout this form 10-K:
"BBL." A standard measure of volume for crude oil and liquid petroleum products; one barrel equals 42 U.S. gallons.
"BCF." Billion Cubic Feet of natural gas at standard temperature and pressure.
"BOE." Barrels of oil equivalent. BOE is calculated by converting 6 MCF of natural gas to 1 BBL of oil.
"BTU" or "British Thermal Unit." The standard unit of measure of energy equal to the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit. One Bbl of crude is typically 5.8 MMBTU, and one standard MCF is typically one MMBTU.
"CO2." Carbon dioxide, a gas that can be found in naturally occurring reservoirs, typically associated with ancient volcanoes, and also is a major byproduct from manufacturing and power production also utilized in enhanced oil recovery through injection into an oil reservoir.
"Developed Reserves." Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
"EOR." Enhanced Oil Recovery projects involve injection of heat, miscible or immiscible gas, or chemicals into oil reservoirs, typically following full primary and secondary waterflood recovery efforts, in order to gain incremental recovery of oil from the reservoir.
"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geologic structural feature and/or stratigraphic feature.*
"Farmout." Sale or transfer of all or part of the operating rights from the working interest owner (the assignor or farm-out party), to an assignee (the farm-in party) who assumes all or some of the burden of development, in return for an interest in the property. The assignor may retain an overriding royalty or any other type of interest. For Federal tax purposes, a farm-out may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.
"Gross Acres or Gross Wells." The total acres or number of wells participated in, regardless of the amount of working interest owned.
"Horizontal Drilling." Involves drilling horizontally out from a vertical well bore, thereby potentially increasing the area and reach of the well bore that is in contact with the reservoir.
"Hydraulic Fracturing." Involves pumping a fluid with or without particulates into a formation at high pressure, thereby creating fractures in the rock and leaving the particulates in the fractures to ensure that the fractures remain open, thereby potentially increasing the ability of the reservoir to produce oil or gas.
"LOE." Means lease operating expense(s), a current period expense incurred to operate a well.
"MBO." One thousand barrels of oil
"MBOE." One thousand barrels of oil equivalent.
"MCF." One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature. Standard pressure in the state of Louisiana is deemed to be 15.025 psi by regulation, but varies in other states.
"MMBOE." One million barrels of oil equivalent.
"MMBTU." One million British thermal units.
"MMCF." One million cubic feet of natural gas at standard temperature and pressure.

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"Mineral Royalty Interest." A royalty interest that is retained by the owner of the minerals underlying a lease. See "Royalty Interest".
"Net Acres or Net Wells." The sum of the fractional working interests owned in gross acres or gross wells.
"NGL." Natural gas liquids, being the combination of ethane, propane, butane and natural gasoline that can be removed from natural gas through processing, typically through refrigeration plants that utilize low temperatures, or through J-T plants that utilize compression, temperature reduction and expansion to a lower pressure.
"NYMEX." New York Mercantile Exchange.
"OOIP." Original Oil in Place. An estimate of the barrels originally contained in a reservoir before any production therefrom.
"Operator." An oil and gas joint venture participant that manages the joint venture, pays venture costs and bills the venture's non-operators for their share of venture costs. The operator is also responsible to market all oil and gas production, except for those non-operators who take their production in-kind.
"Overriding Royalty Interest or ORRI." A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of. See "Royalty Interest".
"Permeability." The measure of ease with which a fluid can move through a reservoir. The unit of measure is a darcy, or any metric derivation thereof, such as a millidarcy, where one darcy equals 1,000 millidarcys. Extremely low permeability of 10 millidarcys, or less, are often associated with source rocks, such as shale, making extraction of hydrocarbons more difficult, than say sandstone traps, where permeability can be one to two darcys or more.
"Porosity." (of sand or sandstone). The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir, stated in percent. Higher porosity rocks provide more storage space for hydrocarbon accumulations than lower porosity rocks in a given cubic volume of reservoir.
“Possible Reserves.” Additional unproved reserves that analysis of geological and engineering data suggests are less likely to be recoverable than Probable Reserves, but have at least a ten percent probability of being recovered.*
"Probable Developed Producing Reserves." Probable Reserves that are Developed and Producing.*
"Probable Reserves." Additional reserves that are less certain to be recovered than Proved Reserves but which, together with Proved Reserves, are as likely as not to be recovered.*
"Producing Reserves." Any category of reserves that have been developed and production has been initiated.*
"Proved Developed Reserves." Proved Reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
"Proved Developed Nonproducing Reserves ("PDNP")." Proved Reserves that have been developed and no material amount of capital expenditures are required to bring on production, but production has not yet been initiated due to timing, markets, or lack of third party completed connection to a gas sales pipeline.*
"Proved Developed Producing Reserves ("PDP")." Proved Reserves that have been developed and production has been initiated.*
"Proved Reserves." Estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*
"Proved Undeveloped Reserves ("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.*

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(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.
"PSI," or pounds per square inch, a measure of pressure. Pressure is typically measured as "psig", or the pressure in excess of standard atmospheric pressure.
"Present Value." When used with respect to oil and gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs to be incurred in developing and producing the proved reserves) computed using a discount factor and assuming continuation of existing economic conditions.
"Productive Well." A well that is producing oil or gas or that is capable of production.
"PV-10." Means the present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme as required by the Securities and Exchange Commission ("SEC"). PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum. See the definition of standardized measure of discounted future net cash flows.
"Royalty" or "Royalty Interest." 1) The mineral owner's share of oil or gas production (typically between 1/8 and 1/4), free of costs, but subject to severance taxes unless the lessor is a government. In certain circumstances, the royalty owner bears a proportionate share of the costs of making the natural gas saleable, such as processing, compression and gathering. 2) When a royalty interest is coterminous with and carved out of an operating or working interest, it is an "Overriding Royalty Interest," which also may generically be referred to as a Royalty.
"Shut-in Well." A well that is not on production, but has not yet been plugged and abandoned. Wells may be shut-in in anticipation of future utility as a producing well, plugging and abandonment or other use.
"Standardized Measure." The standardized measure of discounted future net cash flows (the "Standardized Measure") is an estimate of future net cash flows associated with proved reserves, discounted at 10% per annum. Future net cash flows is calculated by reducing future net revenues by estimated future income tax expenses and discounting at 10% per annum. The Standardized Measure and the PV-10 of proved reserves is calculated in the same exact fashion, except that the Standardized Measure includes future estimated income taxes discounted at 10% per annum. The Standardized Measure is in accordance with accounting standards generally accepted in the United States of America ("GAAP").
"SWIW." Salt water injection well.
"Undeveloped Reserves." Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.*
"Working Interest." The interest in the oil and gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.
"Workover." A remedial operation on a completed well to restore, maintain or improve the well's production.

* This definition may be an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Houston, Texas, on the date indicated.

	Evolution Petroleum Corporation
By:	/s/ ROBERT S. HERLIN Robert S. Herlin Chairman of the Board and Chief Executive Officer (Principal Executive Officer)

Date: September 12, 2014

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

Date	Signature	Title
September 12, 2014	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)
September 12, 2014	/s/ RANDALL D. KEYS Randall D. Keys	President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
September 12, 2014	/s/ DAVID JOE David Joe	Vice President, Controller, Chief Administrative Officer and Corporate Secretary
September 12, 2014	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Director
September 12, 2014	/s/ GENE STOEVER Gene Stoever	Director
September 12, 2014	/s/ WILLIAM DOZIER William Dozier	Director
September 12, 2014	/s/ KELLY W. LOYD Kelly W. Loyd	Director

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INDEX OF EXHIBITS
MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
2.1	Purchase and Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on May 11, 2006)
2.2	Purchase and Sale Agreement I, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.3	Purchase and Sale Agreement II, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
2.4	Conveyance, Assignment and Bill of Sale Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
3.1	Articles of Incorporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.3	Certificate of Amendment to Articles of Incorporation (Previously filed as an exhibit to Form SB 2/A on October 19, 2005)
3.4	Certificate of Designation of Rights and Preferences for 8.5% Series A Cumulative Preferred Stock (Previously filed as an exhibit to the Company's Current Report of Form 8-K on June 29, 2011)
3.5	Bylaws (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 7, 2002)
3.6	Amended Bylaws (Previously filed as an exhibit to Form 10KSB on March 31, 2004)
4.1	Form of Stock Option Agreement for the Natural Gas Systems 2004 Stock Plan (Previously filed as an exhibit to the Current Report on Form 8-K on April 8, 2005)
4.2	Specimen form of the Company's Common Stock Certificate (Previously filed as an exhibit to Form S-3 on June 19, 2013)
4.3	Specimen form of the Company's 8.5% Series A Cumulative Preferred Stock Certificate (Previously filed as an exhibit to Form 8-A on June 29, 2011)
4.4	2004 Stock Plan (Previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.5	Amended and Restated 2004 Stock Plan, adopted December 4, 2007 (previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14A on October 29, 2007)
4.6	Amendment to Amended and Restated 2004 Stock Plan, adopted December 5, 2011 (previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14A on October 28, 2011).
4.7	Form of Restricted Stock Agreement (Previously filed as an exhibit to Form 8-K on May 15, 2009)
4.8	Majority Voting Policy for Directors (Previously filed as an exhibit to the Company's Current Report on Form 8-K on October 31, 2012)
10.1	Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.2	Executive Employment Agreement of Sterling H. McDonald, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.3	Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
10.4	Unit Operating Agreement, by and between NGS Sub Corp. and Denbury Onshore, LLC, dated May 8, 2006 (Previously filed as an exhibit to Form 8-K on June 16, 2006)
10.5	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (Previously filed as an exhibit to Form 8-K on September 22, 2006)
10.6	Asset Purchase and Sale Agreement by and between NGS SUB. CORP. (Seller) and MWM Energy, LLC (Buyer), dated February 15, 2008 (Previously filed as an exhibit to Form 10-Q on May 14, 2008)

10.7	Credit Agreement dated February 29, 2012 among Evolution Petroleum Corporation, the Guarantors and Texas Capital Bank N.A. (incorporated by reference as Exhibit 10.1 to the Company's Form 8-K filed with the SEC on March 6, 2012.

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EXHIBIT NUMBER	DESCRIPTION
10.8	Lease Acquisition Agreement Cowboy Prospect by and between Evolution Petroleum OK, Inc. and Orion Exploration Partners, LLC dated April 17, 2012 (incorporated by reference as Exhibit 10.1 to the Company Form 8-K/A filed with the SEC on August 21, 2012)
10.9	Participation and AMI Agreement by and between Orion Exploration Partners, LLC and Evolution Petroleum OK, Inc. dated April 17, 2012 (incorporated by reference as Exhibit 10.2 to the Company Form 8-K/A filed with the SEC on August 21, 2012)
10.10	First Amendment to the Credit Agreement dated February 29, 2012 among Evolution Petroleum Corporation, the Guarantors and Texas Capital Bank N.A effective November 1, 2012 (Filed herein)
10.11	Second Amendment to the Credit Agreement dated February 29, 2012 among Evolution Petroleum Corporation, the Guarantors and Texas Capital Bank N.A effective May 14, 2014 (Filed herein)
10.12	Technology Assignment Agreement dated June 30, 2011 between Evolution Petroleum Corporation and Daryl Mazzanti (Filed herein)
14.1	Code of Business Conduct and Ethics for Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
21.1	List of Subsidiaries of Evolution Petroleum Corporation (Filed herein)
23.1	Consent of Hein & Associates, LLP (Filed herein)
23.2	Consent of DeGolyer and MacNaughton (Filed herein)
23.3	Consent of W.D. Von Gonten & Co. (Filed herein)
23.4	Consent of Pinnacle Energy Services, LLC (Filed herein)
31.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
31.2	Certification of President and Chief Financial Officer Randall D. Keys Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.1	Certification of Chief Executive Officer Robert S. Herlin Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
32.2	Certification of President and Chief Financial Officer Randall D. Keys Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.1	Audit Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.2	Compensation Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.3	Nominating Committee Charter of the Board of Directors of Natural Gas Systems, Inc. (Previously filed as an exhibit to Form 8-K on May 4, 2006)
99.4	The summary of DeGolyer and MacNaughton's Report as of June 30, 2014, on oil and gas reserves (SEC Case) dated July 31, 2014 and certificate of qualification (Filed herein)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document