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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended June 30, 2013

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: ☒

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: ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See 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 ☒   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: ☒

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 11, 2013, was 28,609,891.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2013 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.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
2013 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 our 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.

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.

"CO_2." 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.

"MMBTU." One million British thermal units.

"MMCF." One million cubic feet of natural gas at standard temperature and pressure.

"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.

"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.*

(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.

Item 1. Business

General

The terms "we," "us," "our," "our Company" and "EPM" refer to Evolution Petroleum Corporation, a Nevada corporation formerly known as Natural Gas Systems, Inc. (Nevada, "NGS"), and, unless the context indicates otherwise, also includes our wholly-owned subsidiaries. Natural Gas Systems, Inc. (Delaware, "Old NGS"), a private Delaware corporation formed in September 2003 was subsequently merged into NGS.

Our petroleum operations began in September of 2003. 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.

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.

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". Prior to July 17, 2006, our stock was quoted on the OTC Bulletin Board under the symbol "NGSY.OB". Prior to May 26, 2004, our stock was quoted on the OTC Bulletin Board under the symbol "RLYI.OB".

At June 30, 2013, we had eleven full-time employees, not including contract personnel and outsourced service providers.

Corporate History of Reverse Merger

Reality Interactive, Inc. ("Reality"), a Nevada corporation that previously traded on the OTC Bulletin Board under the symbol RLYI.OB and the predecessor of Evolution Petroleum Corporation, was incorporated on May 24, 1994, for the purpose of developing technology-based knowledge solutions for the industrial marketplace. On April 30, 1999, Reality ceased business operations, sold substantially all of its assets and terminated all of its employees. Subsequent to ceasing operations, Reality explored other potential business opportunities to acquire or merge with another entity while continuing to file reports with the Securities and Exchange Commission ("SEC").

On May 26, 2004, Old NGS merged into a wholly owned subsidiary of Reality. Reality was thereafter renamed Natural Gas Systems, Inc. ("NGS") and adopted a June 30 fiscal year end. As part of the merger, the officers and directors of Reality resigned, the officers and directors of Old NGS became the officers and directors of NGS, and the crude oil and natural gas business of Old NGS

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* 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.

became that of NGS. Concurrently with the listing of NGS shares on the NYSE Amex (formerly the American Stock Exchange and now the NYSE MKT) during July 2006, NGS was renamed Evolution Petroleum Corporation to avoid confusion with similar names traded on the NYSE Amex and to better reflect our business model.

All regulatory filings and other historical information prior to May 26, 2004 that applied to Reality continue to apply to EPM after the merger.

Business Strategy

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, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both.

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, including approximately 21% beneficially owned by all of our employees.

Our strategy is intended to generate scalable, low unit cost, development and re-development opportunities that minimize or eliminate exploration risks. These opportunities involve the application of modern technology, our own proprietary technology and our specific expertise in overlooked areas of the United States, where we may or may not choose to be the operator.

The assets we exploit currently fit into three types of project opportunities:

- Enhanced Oil Recovery (EOR),
- Bypassed Primary Resources, and
- Unconventional Development, especially utilizing our staff expertise in horizontal drilling.

Our active projects in these categories are:

Enhanced Oil Recovery

Delhi Field—Louisiana

Our mineral interests in the Holt Bryant Unit in the Delhi Field, located in Northeast Louisiana, are currently our most significant assets. 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.

The Unit is currently being redeveloped as an EOR project utilizing CO_2 flood technology following our farmout 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 CO_2. Upon reversion of the deemed payout, regardless of the Operator's actual capital expenditures, we begin bearing 23.9% of all future operating and capital expense and our net revenue interest

increases from 7.4% to an aggregate 26.5%. Our current independent reserves report dated June 30, 2013 assumes the deemed payout to occur on or about the end of calendar year 2013.

At June 30, 2013, our independent reservoir engineers, DeGolyer & MacNaughton ("D&M") increased their estimates of original oil in place (OOIP) by 14.8% to 410 million barrels, compared to prior estimates of 357 million barrels. This increased our net recovery estimates. D&M assigned the following net reserves to our interests at Delhi as of June 30, 2013:

- 13.5 million bbls of proved oil equivalent reserves, with a PV-10 of $455.3 million*
- 7.4 million bbls of probable oil equivalent reserves, with a PV-10 of $ 109.3 million*
- 3.7 million bbls of possible oil equivalent reserves, with a PV-10 of $32.5 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 reserves are not recognized by GAAP, and therefore the PV-10 of probable reserves cannot be reconciled to a GAAP measure. With respect to the above reserve numbers, estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of 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. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

The Operator has planned multiple phases for the installation of the CO_2 flood.

Phase I began CO_2 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 is more than double the size of Phase I, commenced with incremental CO_2 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 subsequently increased to more than 7,500 BO per day before the operator temporarily suspended CO_2 injection in a portion of the field due to the June 2013 environmental event described in *Item 7. "Management's Discussion and Analysis"*.

During 2013, the operator intensified development in the previously redeveloped western side of the field based on production results and new geological mapping that includes the results of seismic data acquired over the last few years. Production response from this work is not expected until 2014. During June 2013, an environmental event 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, which would delay the reversion of our working interest.

We expect that the remaining phases will be installed similarly over the next few years. We further expect that three smaller reservoirs within the Unit and in similar formations and with similar production history will be developed as an additional phase in the EOR project later this decade.

During fiscal 2013, Delhi's Louisiana Light Sweet ("LLS") crude oil sales realized $106.38 per BBL average price, a14% price premium over the $93.34 per BBL sales price we received from our Texas production. We expect that a positive market differential may continue into fiscal 2014.

Bypassed Primary Resource Projects

Following the closing of our Delhi Farmout in June 2006, we began the process of identifying new conventional development and/or redevelopment projects targeting primary petroleum resources previously bypassed by industry in historically productive formations, generally due to inadequate technology or commodity prices. In selecting our candidates:

- We leverage our staff's extensive experience, gained over many years while employed at various large independent oil and gas companies in the pioneering of horizontal drilling practices;

- We seek projects that can effectively and efficiently redeploy projected net cash flows from Delhi Field farm-out and subsequent production;
- We seek projects that can generate multiple, scalable development opportunities with long term production growth; and
- We seek exposure to both crude oil and natural gas opportunities, with an emphasis on crude oil in recent years.

Mississippi Lime—Kay County, North Central 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 Mississippian Lime reservoir in Kay County, Oklahoma within the rapidly growing play in north central Oklahoma and western Kansas. Our leasehold position is located in the eastern, oily 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 is approximately $3.2 million. The joint venture currently holds approximately 11,700 net acres that is east and northeast of the Range Resources leasehold. To date, we have drilled one gross salt water disposal well and reached total depth on our first two horizontally drilled wells in the Mississippian Lime formation, including lateral lengths of approximately 4,100 feet in the Sneath #1-24 and 4,800 feet in Hendrickson #1-1. In both wells, the lateral well bore was placed in the middle of the formation approximately 100 feet below the top. While both wells produced at the fluid rates expected, the quantities of oil and gas were far less than expected. In order to better test the potential of the reservoir in the same manner as nearby wells with reported good results, we have plugged back the lateral of the Hendrickson #1-1 in order to re-perforate and hydraulically fracture the upper portion of the formation. Positive results during the early portion of fiscal 2014 could lead to a third evaluation well. During the fourth quarter of fiscal 2013, we elected to reduce our joint venture interest in undeveloped leases to 33.9%, which resulted in a $1.2 million reduction in both our net property and accounts payable.

As of June 30, 2013, our independent reservoir engineer, Pinnacle Energy Services, assigned to us net probable reserves of 3,280,988 BOE with a PV-10 of $19.5 million* associated with our net interest in 111 gross drilling locations.

Artificial Lift Technology (GARP®)

Our artificial lift technology registered as GARP® (Gas Assisted Rod Pump) was developed by one of our employees. 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 less than $10 per BOE. Letters patent for our GARP® technology were issued on August 30, 2011.

Prior to patent issuance, our GARP® technology was tested on certain marginal producers we own and operate in the Giddings Field. The tests were successful in demonstrating that the process works; however, these candidates were unable to prove commercial application 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 progress at year-end. All of these installations were successful in re-establishing commercial production, however one well was subsequently watered out when an offset well was hydraulically fractured and the water migrated to our well bore. We are in negotiations to further expand the business during fiscal 2014.

With continued success and industry acceptance, we believe GARP® could be applicable to a large number of late stage horizontal and vertical wells worldwide.

Giddings Field—Central Texas

We began leasing activities in the Giddings Field in December 2006 and currently hold 2,134 net developed acres as of June 30, 2013. 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 nonGARP® producing wells and drilling locations.

We retained an approximate 4% 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 our approximate 5% overriding royalty interests in the Woodbine formation on 900 net acres and our 15% back-in working interest on approximately 258 net acres in Grimes County, Texas. We have not yet assigned any reserves to these interests, pending drilling results by the operator.

Total net proved reserves assigned to our GARP® properties in the Giddings Field by our independent reservoir engineer, W.D. Von Gonten & Associates, are 35 MBOE as of June 30, 2013. The total is a decrease of 2,289 MBOE from June 30, 2012 due to Giddings production during the year of 40 MBOE, a series of property divestitures totaling 2,254 MBOE (comprised mostly of PUD's) and positive revisions totaling 5 MBOE. Two GARP® installations were not completed by June 30, 2013 and thus not included in our reserves as of that date.

PV-10 of proved reserves at June 30, 2013 was $0.5 million. See "Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues" under *Item 2. Properties* of this Form 10-K for a reconciliation of PV-10 to the Standardized Measure.

Lopez Field—South Texas

We acquired leases 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.

We currently own leases on approximately 782 net acres at Lopez. As of June 30, 2013, our independent reservoir engineer, W.D. Von Gonten & Associates, recognized two proved producing wells and six gross and net proved undeveloped well locations with 186 MBO of proved reserves. The engineer further assigned 531 MBO of probable reserves to 22 gross and net locations.

While our development activity in the Lopez Field confirmed the potential of our concept, the time and effort required to achieve reserves has lowered the attractiveness of the potential. Consequently, we elected to begin a monetization process of this asset during fiscal 2013 and expect that process to be completed in early fiscal 2014.

Unconventional Resources

Woodford Shale Projects in Oklahoma—Southeast Oklahoma

Following the closing of our Delhi Farmout in June 2006, we identified two unconventional natural gas resource projects targeting the shallow Woodford Shale in Wagoner and Haskell counties of Oklahoma to balance the oily nature of our Delhi asset. These projects met our parameters of low drilling cost and risk, repeatable development and acceptable economics based on a $5+ NYMEX natural gas price.

Due to persistent low natural gas prices and our perception that natural gas prices will likely remain below $5 over the near term, we discontinued our active development in these projects and allowed our leasehold to expire.

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.

Since March 2005 and into 2008, we sold all of our operated crude oil production to Plains Marketing LP, a crude oil purchaser, at competitive field prices. In January of 2008, we also began selling crude oil to Enterprise Crude Oil LLC, a crude oil gathering, transportation, storage and marketing company. Our agreements with both Plains Marketing LP and Enterprise Crude Oil LLC are under normal (thirty day "evergreen") sales contracts. We sell essentially all of our crude oil from our operated properties at Giddings to Enterprise Crude Oil LLC. Oil production from our Lopez Field is 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, ETC Texas Pipeline, LTD., and Copano Field Services/Upper Gulf Coast, L.P. 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 product less a fee and certain operating expenses. The price of natural gas sold to Copano is adjusted upward for the high BTU content. 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	**2013**	**2012**	**2011**
Plains Marketing L.P. (includes Delhi production)	90%	84%	60%
Enterprise Crude Oil LLC	4%	7%	15%
Flint Hills	2%	1%	—%
DCP Midstream, LP	1%	2%	6%
Kinder Morgan (fka Copano Field Services/Upper Gulf Coast, L.P.)	1%	3%	7%
Enervest, LLC	1%	—%	—%
Orion Exploration Partners, LLC	1%	—%	—%
ETC Texas Pipeline, LTD.	—%	3%	12%

The loss of any single purchaser 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 for our oil and natural gas production, which in turn could negatively impact the prices we receive.

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 substantially exceeded the price we received for our Texas oil production since the second half of fiscal 2011. We do not know how long our Delhi oil price will continue to receive a premium price.

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. 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 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

Operating results from oil and natural gas production may 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. 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 and lack of success in adding GARP® installations 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.

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; and depleted reservoirs require successful application of newer technology to unlock incremental reserves.

Our CO_2-EOR project in the Delhi Field, operated by a subsidiary of Denbury Resources Inc., requires significant amounts of CO_2 reserves, development capital and technical expertise, the sources of which to date have been committed by the Operator. Although initial CO_2 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 CO_2-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 a 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 Mississippian Lime project in Oklahoma, although believed to have oil and gas resources, have yet to exhibit any proved reserves. Therefore, the economic outcome is uncertain.

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.

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 90% 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 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 or our interests in the Mississipian Lime play in Oklahoma, and our revenues and future growth are heavily dependent on the success of operations which we do not control. During our fiscal fourth quarter, an environmental event occurred at the Delhi field which resulted in a significant temporary downturn in the daily oil production at the Delhi field which has had a near term impact on the revenues received from our royalty interest and according to the operator, has delayed the reversion date of our working interest.

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, 2013, seven purchasers each accounted for all of our oil and natural gas revenues. The loss of a large single purchaser for our oil and natural gas production could negatively impact the prices we receive.

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

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 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 material value. Our further success in commercializing the technology will depend upon additional positive field tests, acceptance by industry and our ability to defend the technology from competitors through confidentiality and patent protection.

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.

Our profitability is highly dependent on the prices of crude oil, natural gas, and natural gas liquids, which have historically been very volatile.

Our estimated proved reserves, revenues, profitability, operating cash flow and future rate of growth are highly dependent on the prices of crude oil, natural gas and NGLs, which are affected by numerous factors beyond our control. Historically, these prices have been very volatile and are likely to remain volatile in the future. A significant and extended downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow, and could result in a reduction in the carrying value of our oil and natural gas properties and the amounts of our estimated proved oil and natural gas reserves. 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 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. Our future crude oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves. Our near-term future growth and financial condition are dependent upon our ability to realize further production increases expected at Delhi, installations of our GARP® technology, and /or the development of additional oil and natural gas reserves.

We are subject to substantial operating risks that may adversely affect our results of operations.

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. We could suffer substantial losses as a result of any of these events. 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.

We may not be the operator of some of our wells in the future, and we are not the operator of our high value assets in the Delhi Field. As a result, our operating risks for those wells and our ability to influence the operations for these wells will be less subject to our control. Operators of these wells may act in ways that are not in our best interests. If this occurs, the development of, and production of crude oil and natural gas from, some wells may not occur timely or at all, which would have an adverse effect on our results of operations.

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, President and Chief Executive Officer, Sterling H. McDonald, our Vice President and Chief Financial Officer, 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.

The loss of any of our skilled technical personnel could adversely affect our business.

We depend to a large extent on the services of skilled technical personnel to lease, drill, complete, operate and maintain our crude oil and natural gas fields. We do not have the resources to perform all of these services and therefore we outsource many of our requirements. Additionally, as our production increases, so does our need for such services. Generally, we do not have long-term agreements with our drilling and maintenance service 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. Although we believe that we could establish alternative sources for most of our operational and maintenance needs, 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. We also rely on third-party carriers for the transportation and distribution of our production, the loss of any of which could have a material adverse effect on our operations.

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: deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome, secure all of the development capital necessary to fund its and Evolution's cost interests and 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.

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.

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.

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

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. In addition, federal and state regulation of crude oil and natural gas production and transportation could affect our ability to produce and market our crude oil and natural gas on a profitable basis.

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

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

Some of our properties, including our Delhi interests and our acreage in the Mississippi Lime Play in Oklahoma, 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. 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.

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.

Risks Relating to the Oil and Gas Industry

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 cancelled 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 CO_2 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 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. Our drilling schedule and costs may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted prospects will be dependent on a number of factors, including, but not limited to:

- the results of previous development efforts and the acquisition, review and analysis of data;
- the availability of sufficient capital resources to us and the other participants, if any, for the drilling of the prospects;
- the approval of the prospects by other participants, if any, after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for crude oil and natural gas and the availability of drilling rigs and crews;
- our financial resources and results;
- the availability of leases and permits on reasonable terms for the prospects; and
- the success of our drilling technology and our ability to control these operations.

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. There are numerous uncertainties in estimating quantities of proved reserves, including many factors beyond our control.

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 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 93% of our proved reserves at June 30, 2013 are crude oil reserves and 7% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices.

Oil field service and materials' prices may increase, and the availability of such services 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 materials such as steel tubulars, which we do not control. Long lead times and spot shortages may prevent us from, or delay us in, maintaining or increasing the production volumes we expect. 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.

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 domestic production activities relating to oil and natural-gas exploration and development, and (iii) implementing certain international tax reforms, 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. This 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.

We could be adversely affected by a weak domestic or global economy.

The current anemic recovery from a recessionary economic environment has limited the recovery in demand for oil and natural gas and, therefore, in commodity prices, particularly natural gas. If the current economic environment continues, lower realized prices may adversely impact our profitability. These factors could negatively impact our operations and may limit our growth.

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. 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 very volatile.

Our common stock is thinly traded and the market price has been, and is likely to continue to be, highly volatile. For example, during the year prior to June 30, 2013, our stock price as traded on the NYSE MKT ranged from $11.50 to $7.48. The variance in our stock price makes it extremely 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 wide 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 6.3 million shares, or approximately 19% of our beneficial common stock base. JVL Advisors LLC controls approximately 5.4 million shares or approximately 18% 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 currently thinly traded on the NYSE MKT. In the year prior to June 30, 2013, the actual daily trading volume in our common stock ranged from 4,800 shares of common stock to a high of 386,200 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 11, 2013. 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;
- 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.

We have not paid any cash dividends on our common stock since the inception of oil and gas operations.

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, restrictions contained in our Series A preferred stock and any debt instruments, our anticipated capital requirements and other factors that our board of directors may think are relevant.

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.

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, you 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.

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.

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 2013

Our proved and probable reserves at June 30, 2013, 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 engineers, W.D. Von Gonten & Co. ("Von Gonten"), Pinnacle Energy Services L.L.C. ("Pinnacle") and DeGolyer and MacNaughton ("D&M"). Von Gonten was engaged for our Texas properties due to their particular expertise in the geographic and geologic areas covered by their reports. 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. Our probable reserves in Oklahoma were estimated by Pinnacle Energy Services L.L.C. due to their particular expertise in Oklahoma and the Mississippian Lime reservoir. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

The following table sets forth our estimated proved and probable reserves as of June 30, 2013. See Note 17 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 $91.51 per barrel of crude oil and $3.44 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price or, if no historical received price is available, historical price 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, 2013

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)	PV-10
PROVED					
Developed (73% of Proved)	10,078	9	22	10,090	$ 382,133,102
Undeveloped (27% of Proved)	2,705	971	—	3,676	76,828,771
TOTAL PROVED	12,783	980	22	13,766	$ 458,961,873
Product Mix	93%	7%	—%	100%	
PROBABLE					
Developed (32% of Probable)	3,561	—	—	3,561	$ 75,168,830
Undeveloped (68% of Probable)	4,394	1,035	13,407	7,663	59,807,406
TOTAL PROBABLE	7,955	1,035	13,407	11,224	$ 134,976,236
Product Mix	71%	9%	20%	100%	

Summary of Oil & Gas Reserves for Fiscal Year Ended 2012

Our proved and probable reserves at June 30, 2012, 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 engineers, Von Gonten, Pinnacle and D&M. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

The following table sets forth our estimated proved and probable reserves as of June 30, 2012. See Note 17 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 $95.67 per barrel of crude oil and $3.15 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. 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.

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June 30, 2012

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)	PV-10
PROVED					
Developed (60% of Proved)	7,671	112	1,499	8,033	$ 335,956,852
Undeveloped (40% of Proved)	3,967	381	6,361	5,408	109,557,773
TOTAL PROVED	11,638	493	7,860	13,441	$ 445,514,625
Product Mix	87%	4%	9%	100%	
PROBABLE					
Developed (21% of Probable)	2,653	—	—	2,653	$ 58,235,794
Undeveloped (79% of Probable)	7,255		16,620	10,025	116,091,943
TOTAL PROBABLE	9,908	—	16,620	12,678	$ 174,327,737
Product Mix	78%	—	22%	100%	

Summary of Oil & Gas Reserves for Fiscal Year Ended 2011

Our proved and probable reserves at June 30, 2011, 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 engineers, Von Gonten, D&M and Lee Keeling and Associates, Inc. ("Keeling"). Keeling was engaged for our Eastern Oklahoma properties due to their particular expertise in the geographic and geologic areas covered by their report. The scope and results of their procedures are summarized in letters from each of those firms, which are included as exhibits to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2011. See Note 17 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 $90.09 per barrel of crude oil and $4.21 per MMbtu of natural gas. The price of natural gas liquids utilized was based on the historical price received versus the NYMEX basis oil price. 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, 2011

Reserve Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)	PV-10
PROVED					
Developed (39% of Proved)	4,986	101	1,543	5,345	$ 200,532,776
Undeveloped (61% of Proved)	6,582	611	7,861	8,503	174,805,682
TOTAL PROVED	11,568	712	9,404	13,848	$ 375,338,458
Product Mix	84%	5%	11%	100%	
PROBABLE					
Developed (31% of Probable)	1,902	—	—	1,902	$ 33,688,710
Undeveloped (69% of Probable)	4,314	—	—	4,314	41,918,888
TOTAL PROBABLE	6,216	—	—	6,216	$ 75,607,598
Product Mix	100%	—	—	100%	

Changes in Oil and Gas Reserves

During our fiscal year ended June 30, 2013, total proved reserves increased 325 MBOE from 13,441 MBOE at June 30, 2012 to 13,766 MBOE at June 30, 2013. The increase is primarily attributable to 2,806 MBOE of upward revisions at Delhi, partially offset by 227 MBOE of production and divestitures of 2,254 MBOE of our Giddings Field properties. The upward revision of 2,806 MBOE in proved reserves in the Delhi Field is due primarily to revision of geological maps based on production results and acquired seismic data, inclusion of one reservoir with similar features, production history and suitability for EOR, and inclusion of natural gas processing at Delhi. Proved developed reserves increased to 73% of proved reserves, a 13% improvement from 60% of proved reserves that were developed at June 30, 2012. See table below for details.

The upgrade of Probable Reserves to Proved Reserves at Delhi contributed to a decline of 1,454 MBOE during the year. In addition, we sold a portion of our Mississippian Lime joint venture interest back to the operator and accordingly experienced a downward revision in reserves per Mississippian Lime drilling location. The overall decline was partially offset by the upward revision of probable reserves at Delhi due to the addition of natural gas processing. Approximately 32% of our probable reserves are developed compared to 21% as at June 30, 2012.

We added a possible reserves category this year to incorporate the probability of additional recovery of approximately 3,688 MBOE at Delhi associated with unrecovered secondary oil. These reserves are an estimate of the potential recovery of oil not previously recovered during the pressure maintenance phase of operations due to the inadequate sweep efficiency utilized in the pressure maintenance operation prior to the current patterned injection of CO_2 and water. Approximately 72% of our possible reserves are developed as they are associated with current and future wells and existing plant.

During our fiscal year ended June 30, 2012, total proved reserves declined 406 MBOE from 13,847 MBOE at June 30, 2011 to 13,441 MBOE at June 30, 2012. The decrease is primarily attributable to 208 MBOE of production, downward revisions for our Woodford properties in Oklahoma and lease terminations in Giddings Fields, partially offset by an upward revision at Delhi and extensions in South Texas and acquired well bores in the Giddings Fields. The upward revision of 210 MBO in proved oil reserves in the Delhi Field is due primarily to a slight acceleration in the projected reversion date of our approximately 24% working interest based on performance to date. The downward revision of 367 MBOE in Giddings is primarily due to our election to allow certain leases containing proved reserves to expire due to unacceptable economics based on low natural gas prices. The additions and revisions in our properties were offset by production of 208 MBOE. See table below for details.

Major changes in reserve categories and significant additions to probable reserves also occurred during fiscal 2012. Proved developed reserves increased to 60% of proved reserves, a 54% improvement from 39% of proved reserves that were developed at June 30, 2011. The 2,688 MBO increase in proved developed reserves was largely due to development activities at Delhi, wherein the operator expended $96 million of their capital for the benefit our combined accounts. We also experienced two major changes in our probable reserves during fiscal 2012. First, probable reserves increased104% increase over the 6,216 MBOE level at the end of fiscal 2011, to 12,678 MBOE. Virtually all of the 6,462 MBOE increase in probable reserves was due to the undeveloped acreage positions we acquired in the Mississippian Lime play we acquired in Kay County, OK during fiscal 2012. Secondly, probable developed reserves at Delhi increased 39% to 2,653 MBO from 1,902 MBO at yearend fiscal 2011, due to capital expenditures mentioned above. See tables immediately above.

	Delhi Field	Giddings Field	Lopez Field	Oklahoma	Total
Proved reserves, MBOE					
June 30, 2011	10,937.4	2,720.8	61.2	128.1	13,847.5
Production	(136.1)	(69.3)	(1.8)	(1.0)	(208.2)
Revisions	210.3	(367.4)	(60.2)	(127.1)	(344.4)
Sales of minerals in place	—	—	—	—	—
Improved recovery, extensions and discoveries	—	39.7	106.5	—	146.2
June 30, 2012	11,011.6	2,323.8	105.7	—	13,441.1
Production	(180.7)	(39.6)	(4.9)	(1.6)	(226.8)
Revisions	2714.6	4.9	85.0	1.6	2,806.1
Sales of minerals in place	—	(2,254.0)	—	—	(2,254.0)
Improved recovery, extensions and discoveries	—	—	—	—	—
June 30, 2013	13,545.5	35.1	185.8	—	13,766.4

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

The following table provides a reconciliation of PV-10 of all of our proved properties to the Standardized Measure as shown in Note 17 of the consolidated financial statements.

	For the Years Ended June 30	
	2013	2012
Estimated future net revenues	$ 865,335,587	$ 858,510,526
10% annual discount for estimated timing of future cash flows	(406,373,713)	(412,995,901)
Estimated future net revenues discounted at 10% (PV-10)	458,961,874	445,514,625
Estimated future income tax expenses discounted at 10%	(151,741,175)	(161,917,132)
Standardized Measure	$ 307,220,699	$ 283,597,493

The following table provides a reconciliation of PV-10 of each of our proved properties to the Standardized Measure as shown in Note 17 of the consolidated financial statements.

	For the Years Ended June 30	
	2013	2012
Delhi Field	$ 455,297,781	$ 409,117,412
Giddings Field	513,816	35,609,294
Lopez Field	3,150,277	787,919
Oklahoma	—	—
Estimated future net revenues discounted at 10% (PV-10)	$ 458,961,874	$ 445,514,625
Estimated future income tax expenses discounted at 10%	(151,741,175)	(161,917,132)
Standardized Measure	$ 307,220,699	$ 283,597,493

Additional detailed information describing the types of properties we own can be found in Item 1. Business—Business Strategy.

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 each 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 third party engineering firm. The scope and results of our third party engineering firms' procedures are summarized in a letter included as an exhibit to this Annual Report on Form 10-K. A letter which identifies the professional qualifications of each of the independent engineering firms who prepared the reserve reports are also filed as exhibits to this Annual report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves at June 30, 2013 were 3,676 MBOE. Future development costs associated with our proved undeveloped reserves at June 30, 2013 totaled approximately $50.4 million. The 1,732 MBOE decrease in proved undeveloped reserves from 5,408 MBOE as of June 30, 2012 is attributable to the sale of 1,840 MBOE of our Giddings Field properties partially offset by positive revisions of 108 MBOE.

None of our proved undeveloped locations at June 30, 2013 have remained undeveloped for five years from the date of initial recognition as proved undeveloped reserves.

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, 2013		Year Ended June 30, 2012		Year Ended June 30, 2011	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Crude oil (Bbls)	196,379	$ 105.34	151,081	$ 109.53	57,965	$ 97.86
Natural gas liquids (Bbls)	7,272	$ 34.81	12,611	$ 49.18	18,704	$ 47.77
Natural gas (Mcf)	139,006	$ 2.95	266,777	$ 2.98	238,608	$ 4.04

Average production costs, excluding ad valorem and production taxes, per unit of production (using a six to one conversion ratio of Mcf's to barrels) were approximately $8, $8 and $11 per BOE for the years ended June 30, 2013, 2012 and 2011, respectively.

Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2013 increased 9% to 226,819 BOE, compared to 208,156 BOE for the year ended June 30, 2012. Our sales volumes for the year ended June 30, 2013 included 180,658 Bbls of oil from Delhi compared to 136,074 Bbls of oil during the previous fiscal year, and 46,161 BOE in aggregate from our Giddings and Lopez Fields in Texas and our Oklahoma properties, compared to 72,082 BOE during the previous fiscal year. Production from our Giddings properties were impacted by the divestments of our nonGARP® producing wells during the year.

Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2012 increased 79% to 208,156 BOE, compared to 116,437 BOE for the year ended June 30, 2011. Our sales volumes for the year ended June 30, 2012 included 136,074 Bbls of oil from Delhi compared to 44,141 Bbls of oil during the previous fiscal year, and 72,082 BOE in aggregate from our Giddings and

Lopez Fields in Texas and our Oklahoma properties, compared to 72,296 BOE during the previous fiscal year.

Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2011 decreased 7% to 116,437 BOE, compared to 125,515 BOE for the year ended June 30, 2010. Our sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi compared to 6,333 Bbls of oil during the previous fiscal year and 71,010 BOE from our properties in the Giddings Field in Texas compared to 119,182 BOE during the previous fiscal year.

First EOR oil production at Delhi began in mid-March 2010. Our interests in the Delhi Field comprise approximately 98% of our total proved reserves as of June 30, 2013. The average sales price per barrel of crude oil at Delhi was $106.38 for the year ended June 30, 2013, with no associated production costs.

Production from our properties in the Giddings Field decreased 43% from 69,260 BOE during the fiscal year ended June 2012 to 39,643 BOE during the fiscal year ended June 30, 2013 due to the divestment of our nonGARP® producing wells and normal production decline. Our remaining interests in the Giddings Field consist of a nonmaterial portion of our total proved reserves as of June 30, 2013. The average sales price per BOE at Giddings was $45.46 for the year ended June 30, 2013. The associated production cost in Giddings for the year ended June 30, 2013 (not including ad valorem and production taxes) was $28.51 per BOE.

Drilling Activity

The following table sets forth our drilling activity. During 2013, we completed 2 gross and 0.8 net wells in Kay County, Oklahoma. We also plugged and abandoned 1 gross and 0.2 net well in the Giddings Field. During 2012, we drilled and completed one gross and net well in the Lopez Field, declared dry two wells in Wagoner County, Oklahoma, and plugged and abandoned one well in our Giddings Field. One well drilled in the Lopez Field was temporarily inactive pending permitting. In 2011, we drilled and completed 3 gross and 0.6 net wells in the Giddings Field and plugged and abandoned one Wagoner County, Oklahoma well, drilled in the previous year as a dry hole.

	Year Ended June 30,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled						
Development	—	—	—	—	3.0	0.6
Exploratory	2.0	0.8	1.0	1.0	—	—
Total	2.0	0.8	1.0	1.0	3.0	0.6
Nonproductive dry wells drilled						
Development	1.0	0.2	—	—	—	—
Exploratory	—	—	—	—	1.0	1.0
Total	1.0	0.2	—	—	1.0	1.0

Present Activities

As of June 30, 2013 there were 2 gross and 0.8 net wells in Kay County, Oklahoma that were completed during the year and one gross and 0.45 net salt water disposal well that was drilled in the previous year and completed in the current year.

Certain wells drilled and completed waiting on pipeline in Wagoner County, Oklahoma remain shut-in and we do not expect to establish pipeline connections prior to sale or lease expiration. One well acquired and re-entered in 2011 and completed in 2012 in Haskell County, Oklahoma was established as a producing well with 5.8 MMCF of sales during 2012. In 2012, that well was shut-in and resumption of production is not expected.

Two gross and net wells were drilled and completed, but waiting on permit, as of June 30, 2012 in the Lopez Field in Texas. One of the wells is a salt water injection well and one is a producer well. Both wells are shut-in as of June 30, 2013.

The operator of the Delhi Field continued development through drilling and well re-entering activities in the western half of the field during 2013. CO_2 injection was increased during the year as additional injection wells were added during the year, except for temporary cooling capacity issues early in the first quarter, scheduled plant maintenance operations during the third quarter, and a temporary suspension of injection in a portion of the field due to an environmental event late in the fourth quarter, all as discussed at "Delhi Field EOR" in Management's Discussion and Analysis of Financial Condition and Results of Operations. As our interest in the Delhi Field is currently an overriding royalty interest, we do not show gross and net well activity in Delhi.

For further discussion, see "Highlights for our fiscal year 2013" and "Looking forward into 2013" 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, 2013, we had no delivery commitments.

Productive Wells and Developed Acreage

			Gross (Net)			
Area	**Gross Developed Acres**	**Net Developed Acres**	**Producing Wells**		**Inactive Producing Wells**	
Giddings	2,168	2,134	4.0	(3.9)	9.0	(9.0)
OK	1,399	630	2.0	(0.8)	3.0	(3.0)
Lopez	655	655	2.0	(2.0)	1.0	(1.0)
Total	4,222	3,419	8.0	(6.7)	13.0	(13.0)

Our developed acreage at June 30, 2013 totaled 3,419 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 two wells subject to a back-in reversion of 22.5%, and a 90.5% working interest in one well subject to a back-in reversion of 22.5%. Nine producing wells in which we have a 100% working interest and another in which we have a 99% interest are currently shut-in. We hold 655 net acres in Webb and Duval Counties in South Texas comprising a 100% working interest in two producing wells and a third producer currently shut-in. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved reserves at Delhi are 74% proved developed, but we do not recognize net acres in the EOR project at Delhi prior to our working interest reversion , currently projected to occur during fiscal year 2014.

Our developed acreage at June 30, 2012 totaled 5,912.5 net acres, of which 5,004.9 net acres were in the Giddings Field comprising a 100% working interest in eleven producing wells, a 99% working interest in one well subject to a back-in reversion of 22.5%, and a 20% BPO WI in three producing wells. One producing well in which we have a 99% working interest is currently shut-in. We hold 654.6 net acres in Webb and Duval Counties in South Texas comprising a 100% working interest in two producing wells and a third producer currently shut-in waiting on permit. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved

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reserves at Delhi are 68% proved developed, but we do not recognize net acres in the EOR project at Delhi prior to reversion of our working interest.

Our developed acreage at June 30, 2011 totaled 5,362 net acres in the Giddings Field, consisting of a 100% working interest in ten producing wells and a 20% BPO WI in three producing wells, 100 net acres in Haskell County, OK with one 100% WI producing well, 153 net acres in Wagoner County, OK with one 100% WI nonproducing shut-in well and 446 acres in Webb County, Texas with one 100% WI producing well. We also own mineral and overriding royalty interests aggregating 7.4% in our CO_2-EOR project in the Delhi Field. Our proved reserves at Delhi are 45% proved developed, but we do not recognize net acres in the EOR project at Delhi prior to reversion of our working interest.

Undeveloped Acreage

As of June 30, 2013, we held approximately gross 24,723 and 7,117 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	10,960	3,725
Lopez Field, South Texas	127	127
Delhi Field, Louisiana*	13,636	3,265
Total	24,723	7,117

* 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% 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 that is subject to expiration over the next three years, if not renewed or extended by option is approximately 1,468 acres in fiscal 2014 and 2,384 acres in 2015.

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

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

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

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 fiscal year 2013, 2012 and 2011, the high and low sales prices for EPM as reported by the NYSE MKT.

NYSE MKT: EPM

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

2012:	High	Low
Fourth quarter ended June 30, 2012	$ 9.71	$ 7.50
Third quarter ended March 31, 2012	$ 10.14	$ 7.97
Second quarter ended December 31, 2011	$ 8.83	$ 6.50
First quarter ended September 30, 2011	$ 7.85	$ 5.90

2011:	High	Low
Fourth quarter ended June 30, 2011	$ 8.80	$ 6.44
Third quarter ended March 31, 2011	$ 8.39	$ 5.52
Second quarter ended December 31, 2010	$ 6.85	$ 5.50
First quarter ended September 30, 2010	$ 6.01	$ 4.10

Holders

As of June 30, 2013, there were 28,609,969 shares of common stock issued and outstanding, held by approximately 350 holders of record.

Dividends

We have never declared or paid any cash dividends with respect to our common stock since inception of oil and gas operations, and 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.

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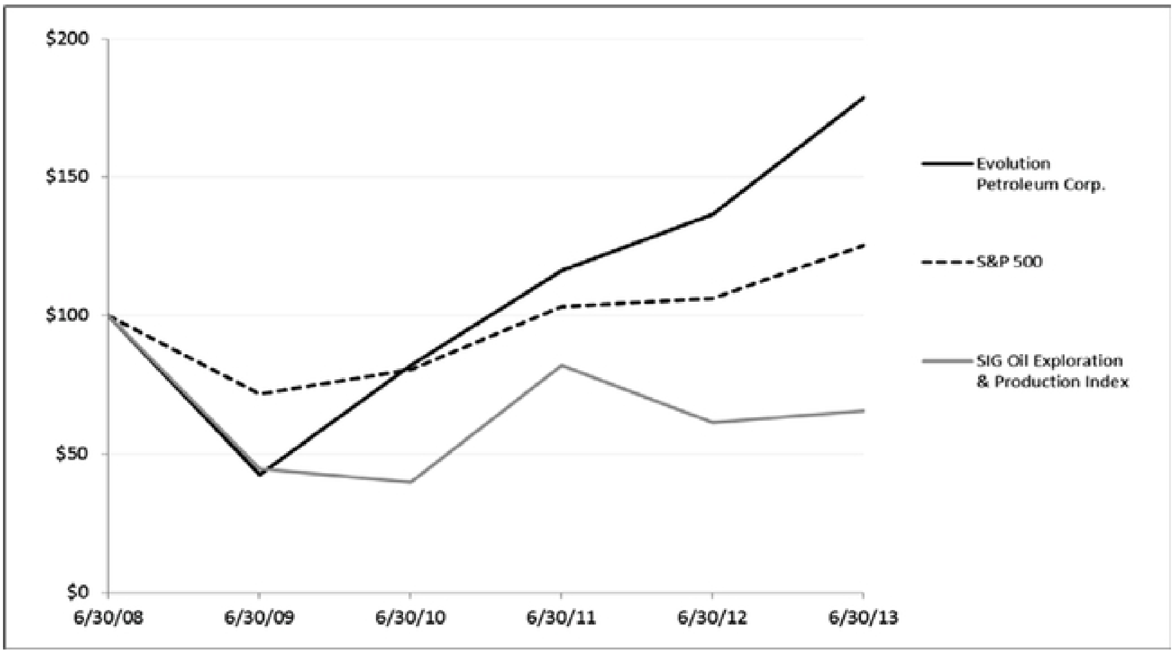
Performance Graph

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, 2008 to June 30, 2013 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, 2008 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.



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	3,785,320(1)	$ 2.11	800,914
Equity compensation plans not approved by security holders	1,038,665(2)	$ 1.56	—
Total	4,823,985	$ 1.99	800,914

(1) On May 26, 2004, we, as Reality Interactive, Inc., executed an Agreement and Plan of Merger with Natural Gas Systems, Inc., a Delaware corporation (the "Merger"). In connection with the Merger, we assumed the obligations of 600,000 stock options under our acquired subsidiary's 2003 Stock

Option Plan. During the year 470,000 options were exercised on this plan. As of June 30, 2013, no shares remain issuable upon exercise of stock options under the 2003 Stock Option Plan and no further options shall be issued there under. As of June 30, 2013, there were 3,945,195 shares of common stock issuable upon exercise of outstanding stock options, 159,875 options that were exercised and 1,753,891 shares of common stock issued directly under the Amended and Restated 2004 Stock Plan, leaving 800,914 shares of common stock available for issuance.

(2) In addition to assuming certain obligations listed in footnote 1 above, in connection with the Merger, we also assumed outstanding warrants to purchase shares of common stock issued in connection with arranging the merger and in connection with capital raising. Total warrants outstanding as of June 30, 2013 related to these activities were 1,165 with a weighted average exercise price of $2.50. Also included were 1,037,500 warrants with a weighted average exercise price of $1.56 issued in connection with employment and or compensation arrangements, including a warrant to purchase 287,500 shares of common stock in connection with Mr. Herlin's employment agreement with the Company, a warrant to purchase 200,000 shares in connection with Mr. Mazzanti's employment agreement with the Company, a warrant to purchase 400,000 shares of common stock in connection with Mr. Herlin's annual performance incentives, including warrants in lieu of cash bonus, and a warrant to purchase 150,000 shares of common stock in connection with Mr. McDonald's annual performance incentives, including warrants in lieu of cash bonus.

Recent Sales of Unregistered Securities

During its fourth quarter ended June 30, 2013, the Company received shares of common stock from certain of its employees for their payroll tax liabilities arising from recent vestings of restricted stock. The acquisition cost per share reflected the weighted-average market price of the Company's shares at the dates vested.

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, 2013 to April 30, 2013	2,130 shares of Common Stock	$ 9.99	Not applicable	Not applicable
May 1, 2013 to May 31, 2013	none	—	—	—
June 1, 2013 to June 30, 2013	8,942 shares of Common Stock	$ 10.59	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.

	Year Ended June 30				
	2013	2012	2011	2010	2009
Income Statement Data					
Revenues	$ 21,349,920	$ 17,962,038	$ 7,530,875	$ 5,021,901	$ 6,095,183
Lease operating expense	1,713,833	1,708,235	1,298,650	1,616,767	1,281,989
Production taxes	66,905	66,764	80,677	48,312	158,794
Depreciation, depletion, and amortization	1,300,207	1,136,974	563,104	1,818,110	2,461,162
Accretion expense	72,312	77,505	59,913	61,054	37,601
General and administrative expense	7,495,309	6,143,286	5,335,384	5,092,243	5,896,366
Income (loss) from operations	10,701,354	8,829,274	193,147	(3,614,585)	(3,740,729)
Other income (expense)	(43,165)	3,778	14,214	55,054	122,272
Income tax provision (benefit)	4,029,761	3,700,922	448,914	(1,171,824)	(1,016,864)
Net income (loss) attributable to the Company	$ 6,628,428	$ 5,132,130	$ (241,553)	$ (2,387,707)	$ (2,601,593)
Dividends on Series A Preferred Stock	674,302	630,391	—	—	—
Net income (loss) attributable to common shareholders	$ 5,954,126	$ 4,501,739	$ (241,553)	$ (2,387,707)	$ (2,601,593)
Earnings per share:					
Basic	$ 0.21	$ 0.16	$ (0.01)	$ (0.09)	$ (0.10)
Diluted	$ 0.19	$ 0.14	$ (0.01)	$ (0.09)	$ (0.10)

	June 30, 2013	June 30, 2012	June 30, 2011	June 30, 2010	June 30, 2009
Balance Sheet Data					
Total current assets	$ 27,436,076	$ 16,769,789	$ 6,357,840	$ 6,229,351	$ 8,873,786
Total assets	66,556,296	58,955,486	39,951,953	37,195,075	37,828,823
Total current liabilities	2,632,750	5,088,917	2,211,932	1,287,699	1,237,904
Total liabilities	11,720,135	12,332,698	6,487,196	5,717,882	6,072,229
Stockholders' equity	54,836,161	46,622,788	33,464,757	31,477,193	31,756,594
Common stock outstanding	28,608,969	27,882,224	27,612,916	27,061,376	26,530,317

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

Executive Overview

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, underdeveloped oil and natural gas resources and exploit them through the application of capital, sound engineering and modern technology to increase production, ultimate recoveries, or both.

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 approximately 21% beneficially owned by our employees.

Our strategy is intended to generate scalable, low unit cost, development and re-development opportunities that minimize or eliminate exploration risks. These opportunities involve the application of modern technology, our own proprietary technology and our specific expertise in overlooked areas of the United States.

The assets we exploit currently fit into three types of project opportunities:

- Enhanced Oil Recovery (EOR),
- Bypassed Primary Resources, and
- Unconventional Development.

We expect to fund our base fiscal 2014 development plan from working capital, with any increases to the base plan funded out of working capital, net cash flows from our properties in the Giddings and Delhi Fields and appropriate financing vehicles.

Highlights for our fiscal year 2013

Oil & Gas Reserves

- **PV-10 of Proved Reserves increased 3% to $459 million from last year's $446 million, despite the aggregate sales of 3.0 MMBOE of reserves and a lower oil price.** The increase in PV-10 (a non-GAAP measure reconciled to the GAAP measure below) was primarily due to positive revisions in our Delhi reserves offset by the sale of most of our nonGARP® assets in the Giddings Field and a portion of our Mississippian Lime leasehold as well as 0.2 MMBOE of production and a 7% lower oil price at Delhi. The positive revisions at Delhi were due to upgrades of probable reserves, increased OOIP based on revised geological maps developed from acquired seismic data, field performance and the inclusion of natural gas processing as part of the project.

- **Proved Developed Reserves increased 26% to 10.1 million BOE compared to 8.0 MMBOE in 2012, or 73% of total proved volumes compared to 60% the previous year.** The increase in proved developed reserves is primarily due to development expenditures by the operator of our Delhi Field.

- **Our black oil volumes increased from 87% of proved reserves to 93% in 2013.**

- **PV-10 of Probable Reserves decreased 23% to $135 million on an 11% decrease in volumes to 11.2 million BOEs.** Half of the decrease in volumes was a result of the sale of a portion of our Mississippian Lime leasehold, and the balance of the decrease was due to an upgrade of reserves to the proved category and a decrease in recovery per Mississippian Lime drilling location, offset by added reserves from gas processing at Delhi.

	Proved			Probable		
	2013	2012	Change	2013	2012	Change
Reserves MMBOE	13.8	13.4	2%	11.2	12.7	(12)%
% Developed	73%	60%	13%	32%	21%	11%
Liquids %	100%	91%	9%	80%	78%	2%
PV-10*	$ 459	$ 445	3%	$ 135	$ 174	22%
(In millions)						

* We believe the presentation 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 the relative monetary significance of their oil and natural gas properties. PV-10 is not intended to represent the current market value of our estimated oil and natural gas reserves, nor should it be considered in isolation or as a substitute for the Standardized Measure of after-tax discounted future net cash flows as defined under GAAP. See "Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues" under *Item 2. Properties* of this Form 10-K for a reconciliation of PV-10 to the Standardized Measure.

Projects (Additional property information is available under *Item 1. Business, Item 2. Properties, Notes to the Financial Statements and Exhibits 23.2-23.4* of this Form 10-K)

Delhi Field EOR—Northeast Louisiana

As of June 30, 2013, D&M's independent reserve report for our Delhi interests reflects:

- an assumed reversionary working interest payout date of January 1, 2014,
- a 14.8% increase in estimated original oil in place (OOIP) to 410 million barrels, compared to prior estimates of 357 million barrels, which includes accelerated development of one smaller reservoir from late in the decade to the 2014-2016 timeframe,
- continued roll-out of the CO_2 flood through 2016,
- installation of natural gas processing to recover methane and heavier NGLs that are currently being produced and re-injected back into the field with the recycled CO_2 stream,
- continued expansion into three small reservoirs at the end of the decade, and
- the addition of possible reserves to account for secondary recovery reserves not produced during the pressure maintenance phase of the field that utilized a limited sweep of the reservoir with injected water as compared to a more efficiently designed water flood.

Proved Reserves estimates increased 23% to 13.5 million BOE at Delhi, based on expected future net capital expenditures of approximately $17.3 million in calendar 2014, $20.9 million in calendar 2015 and $18.4 million in calendar 2016. The inclusion of natural gas processing beginning in 2016 is based upon a third party engineering study performed with the input of the operator, vetted by D&M, and based on the measured levels of hydrocarbons in our recycle stream. D&M assigned the following net reserves to our interests at Delhi as of June 30, 2013:

- 13,545,519 Bbls of proved oil equivalent reserves, with a PV-10 of $455.3 million*
- 7,412,280 Bbls of probable oil equivalent reserves, with a PV-10 of $ 109.3 million*
- 3,688,277 Bbls of possible oil equivalent reserves, with a PV-10 of $32.5 million*
- 74% of proved volumes are developed.
- 48% of probable reserves are developed.
- 72% of possible reserves are developed.

Proved reserves at Delhi are associated with a projected 13% recovery of OOIP and condensate recovered from the recycle gas stream.

Probable reserves are associated with an increase in recovery from 13% to 17% of OOIP from existing and future wells, extension of the CO_2 flood into three small reservoirs at a point in time beyond the five year development period allowed for proved undeveloped reserves, and natural gas and NGLs recovered from the recycle gas stream.

Possible reserves are associated with an increase in recovery from 17% to 20% of OOIP from existing and future wells due to secondary recovery reserves not produced during the pressure maintenance phase of the field as a result of limited sweep efficiency of injected water. Possible reserves are generally projected to be produced during the latter life of the project. Consequently,

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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 probable and possible reserves cannot be reconciled to a GAAP measure.

capital expenditures to date in the field and in the processing plant have developed not just proved, but also probable and possible reserves, thus leading to the categories of probable and possible developed reserves.

Currently, all of our Delhi production comes from our 7.4% royalty interest that bears no cost or expense. At reversion, our net revenue interest will increase from 7.4% to 26.5%, and we will begin bearing 23.9% of all costs. We expect that the net cash flow from our combined revenue interest after reversion will more than amply cover the projected remaining capital expenditures.

Year-over-year, proved developed reserves increased from 68% to74% of total Delhi proved reserves due to continued investment by the operator and performance in the field, partially offset by the inclusion of new PUD reserves due to the addition of natural gas processing.

Annual production sales increased 33% year-over-year at Delhi, from 372 net BO per day (5,021 gross BO per day) to 495 net BO per day (6,684 gross BO per day), with Phases I thru IV currently producing to varying degrees. Sequentially, FQ4-2013 production sales declined 6% from 566 net BOD (7,645 gross) in FQ3-13 to 532 net BOD (7,188 gross).

During our fourth fiscal quarter, revenue from the Delhi field sequentially decreased due to lower oil prices, lower production resulting from scheduled plant maintenance, infill drilling, and the effect of a temporary suspension of CO_2 injections in the southwestern most flank of the field where a release of well fluids occurred in June of 2013.

In the near term, we expect our revenues to be temporarily impacted as a result of the environmental event at Delhi, as gross field production has dropped from the fourth fiscal quarter average of 7,188 BOPD to between 5,500 and 6,000 BOPD. The operator has projected that CO_2 injection will resume in the affected area by the 4th calendar quarter of 2013, after which the field's affected oil production is anticipated to gradually recover. The operator has reported that the released fluids were primarily CO_2, with smaller amounts of salt water, natural gas and a smaller amount of oil. The operator took immediate remedial action to stop the release and contain and remove all liquids in the affected area, and is working with government officials and agencies to complete the remediation. During the remediation, the operator has temporarily halted CO_2 injection in the affected area surrounding one or more previously abandoned wells suspected of being the cause of the leak in order to relieve pressure during the remediation. Production from wells in the affected area has continued, but has also declined due to the reduced injection volumes that provide the necessary "drive" for tertiary oil production. Production levels in other developed areas of the field have not been affected.

At this time, we are not working interest owners in the Holt Bryant Unit of the Delhi Field and therefore are not bearing any cash costs of the remediation, the amount of which the operator has recently estimated to be a minimum of $70 million. However, revenues to our royalty interest are being temporarily impacted by the reduction in oil production in the affected area, and the impact is expected to continue into our second quarter of fiscal 2014.

An increase in lease operating costs due to the remediation, to the extent not covered by the operator's indemnity of us and contractually assumed obligations, net of any associated insurance reimbursements, are currently expected to delay the date that our reversionary working interest becomes effective. The extent of the delay is uncertain and also depends upon other variables including the temporary reduction in purchased CO_2 volumes and oil prices.

We have no current expectation that ultimate field recoveries and reserves at Delhi will be materially impacted, and our current reserves as of June 30, 2013 include the expected impact of this event based on an assumed reversion date. We are continuing to monitor the field operations in our limited role as a non-working interest royalty owner.

To date, the operator has reported expending $525 million on the project to complete four of six planned phases and associated pipeline and infrastructure construction. Our reversion, however, is based solely on our deemed $200 million reversionary payout amount. Until reversion, our net production is being realized from our 7.4% royalty interest that is free and clear of all cost, except for a pipeline transportation tariff of approximately $2.00 per barrel. Our realized oil price at Delhi tracks Louisiana Light Sweet oil price, which has been similarly tracking Brent crude oil price during fiscal 2013. As a result, our average realized price for the year at Delhi was $106 per barrel.

Mississippi Lime—North Central Oklahoma, Kay County

In April 2012, we entered the Mississippi Lime play east of the Nemaha Ridge in north central Oklahoma through a joint venture ("JV") with a private company based in Tulsa, Oklahoma. Our position is in Kay County, where the Mississippian Lime formation is well-defined, but not substantially depleted, by previous vertical development, and the area historically has shown higher oil content. The JV plans to redevelop this play with horizontal drilling and staged fracturing technology. The JV, operated by our partner, owns approximately 11,700 net acres within a footprint of approximately 24,000 gross acres.

During fiscal 2013, the operator completed the first two gross (.8 net) producer wells on our acreage. Following more than six months of high fluid production, but substantially less than expected oil and gas production, we completed a study of recent wells in the area offsetting our leasehold to potentially identify differentiating characteristics between successful and unsuccessful. That study concluded that successful horizontal wells were typically completed high in the formation, and unsuccessful wells were typically completed in the lower part of the formation. With the JV's initial two evaluation wells having been drilled in the middle of the formation, the partners agreed to production test a recompletion high in the vertical part of one JV well. This work is currently underway.

Also during fiscal 2013, we elected to sell back to the JV operator a portion of our interest totaling 1,189 net acres in exchange for the liquidation of our remaining $1.2 million carry obligation. As a result, our net property account and our accounts payable were reduced by $1.2 million. Consequently, our JV interest in all undrilled sections decreased to 33.6%.

At June 30, 2013, our independent reservoir engineers, Pinnacle Energy Services, LLC, assigned probable undeveloped reserves totaling 3.3 million BOE, net to our interest, with a PV-10 of $19.5 million. These reserves represent an approximate $^{1}/_{3}$rd reduction in recovery per drilling location compared to the reserves report of June 30, 2012, and the reduction is based on the results of our first two evaluation wells and results of drilling in the area by other operators. The 3.3 million BOE of probable reserves compares to 6.4 million BOE, with a PV-10 of $69 million at June 30, 2012. The estimated reserves are 62% black oil and 38% liquids rich natural gas. Our reserves are derived from 4,355 net acres to our interest across 111 gross drilling locations on 213 acre spacing, or three locations for each 640 acre section. On this basis, full development costs are estimated to be $56.8 million, net to our interest, or $17.30 per net BOE. We are developing the leasehold initially on 160 acre spacing based on current industry expectations.

GARP®

During 2013, we installed our GARP® technology on three wells, one pursuant to each of two commercialization agreements in place and one installation in a well we acquired. All three tests were completed with good results, but one installation under a commercialization agreement was subsequently watered out due to an offset well being hydraulically fractured by another operator. In the other two wells, we were able to significantly increase production and reserves while substantially extending the economic lives and retaining leases.

Due to the success to date, we are now in final discussions to expand the application of GARP® to a larger group of wells.

Giddings Field—Central Texas

During fiscal 2013, we divested of the bulk of our nonGARP® Giddings Field assets. As part of the divestment, we retained an approximate 4% overriding royalty interest on 2,094 acres on all depths below the base of the Austin Chalk and also have the right to receive a spud fee of $50,000-$100,000 per proved drilling location divested. In a fiscal 2012 farmout, we retained our approximate 5% overriding royalty interests in the Woodbine formation on 900 net acres and our 15% back-in working interest on approximately 258 net acres in Grimes County, Texas

Lopez Field—South Texas

During fiscal 2013, we drilled and completed a producer well and a salt water injection well. Both of these wells are currently shut in. The two producers drilled and completed the previous year yielded the expected level of oil production during the year, and our independent reservoir engineer, Von Gonten, assigned proved developed reserves of 37 MBO with PV-10 of $1.3 million and 149 MBO of proved undeveloped reserves with PV-10 of $1.9 million to six drilling locations. He further assigned probable reserves of 531 MBO to 22 drilling locations with PV-10 of $6.1 million.

While our development activity in the Lopez Field confirmed the potential of our concept, the time and effort required to achieve reserves has lowered the attractiveness of the potential. Consequently, we elected to begin a monetization process of this asset during fiscal 2013 and expect that process to be completed in early fiscal 2014.

Operations

- **Fiscal 2013 net income increased 33% to $6.0 million, a $1.5 million increase over fiscal 2012 net income of $4.5 million.**

- **Revenues increased 19% to $21.3 million, compared to $18.0 million in fiscal 2012.** The revenue increase was due to a 9% BOE increase in sales volumes to 227 MBOE and a 9% increase in realized prices that averaged $94.13 per BOE. Delhi was the largest contributor to revenue growth due to its 33% sales volume increase that was partly offset by a 4.4% decrease in realized average prices to $106.38 per BO.

- **We realized $3.5 million in proceeds by monetizing non-core Giddings properties during fiscal 2013.** Comparing this year's performance of properties sold this year to fiscal 2012, revenue was $1.25 million lower and volumes were 31,600 lower.

- **Operating costs, including LOE, production tax, DD&A and G&A, increased 16% to $10.6 million, up 2.7% over fiscal 2012 on a BOE basis to $46.52 per BOE.** The key driver to the $1.4 million increase was a $1.3 million increase in G&A expense, reflecting higher legal expense, bonus, salary and benefits, compliance costs and property sale transaction fees.

- **Non-cash, stock-based compensation expense of $1.5 million comprised 21% of general and administrative expense for fiscal 2013.** Non-cash, stock-based compensation expense remains an important part of our total compensation program, as a small company in competition for talented staff with numerous, more established other companies, to help motivate and retain high performing employees and consultants, in addition to conserving our cash resources.

For further details, see "Results of Operations" below.

Finances

- **Working capital more than doubled to $24.8 million, compared to $11.7 million at June 30, 2012.** At June 30, 2013, working capital included $25 million of cash. The $13.1 million increase in working capital since June 30, 2012 was due primarily to $10.5 million increase in balance sheet cash, a $0.1 million increase in all other current assets and a $2.5 million reduction in current liabilities due to a $3.1 million decline in joint venture payables, partially offset by an aggregate $0.7 million increase from all other current liabilities.

- **Cash flows from operations covered our general and administrative expenses and all of our capital expenditures.** Operating cash flow was $11.9 million and cash capital expenditures were $4.9 million.

- **We added an unsecured standby credit facility in the amount of $5 million, none of which has been drawn down as of the date of this filing.**

- **We remained debt free.** All of our expenditures were funded solely by working capital and we ended our fiscal year with no funded debt.

Looking forward into Fiscal 2014

Capital Budget

Our capital expenditures for fiscal 2014 are expected to be at least $18 million across our three core assets.

Delhi Field—

We expect our net capital expenditures in Delhi to approximate $17 million for the roll-out of the next phase of the CO_2 project, assuming reversion of our working interest occurs by January 1, 2014. We further expect that cash flows from the working interest will be in excess of the net capital expenditures expected.

Mississippian Lime—

Further capital expenditures will be subject to success in the currently active recompletion test of one well and, if successful, drilling results of the anticipated third evaluation well. In addition, our capital expenditures will be impacted by the level of participation by our JV partner and our ability to bring in another partner if the JV operator is unable to participate. Each well is expected to cost approximately $3.2 million on a 100% working interest basis.

GARP®—

Capital expenditures are subject to the number of installations pursuant to an agreement currently being finalized, and any other commercialization agreements entered into. At this time, our expectation is for capital expenditures to be at least $1 million, and could reach or exceed $3 million.

Realizing shareholder value

The board of directors and management continue to be highly focused on creating value for shareholders and delivering that value to shareholder in an efficient and timely manner. Consequently, we are regularly reviewing potential acquisitions, new projects, dividends, and other opportunities. As part of that effort, we renewed our Form S-3 shelf registration and expanded its capacity to $500 million in order to increase our financial flexibility and options.

Continued improvement in financial results, through increasing production and revenues.

Liquidity and Capital Resources

At June 30, 2013, our working capital was $24.8 million compared to $11.7 million at June 30, 2012. The $13.1 million increase in working capital since June 30, 2012, was due primarily to increased cash of $10.5 million together with a $2.5 million reduction in current liabilities reflecting a $3.1 million decrease in joint venture payables partially offset by an aggregate increase in other current liability items. During our fiscal year ended June 30, 2013, incurred capital expenditures were $3.4 million, which was net of a $1.2 million joint venture leasehold cost reduction (discussed below) with $0.2 million incurred leasehold acquisitions, and $4.4 million incurred for development activities. Principal development activities occurred in Mississippian Lime and, to lesser extents, in the Giddings (primarily for GARP® wells) and Lopez Fields. Under provisions of our joint venture agreement with Orion, we elected to offset the $1.2 million remaining payable for purchased acreage against related leasehold purchase cost, reducing our joint venture interest in initial undrilled leasehold from 45% to 33.9%. During the year we realized $3.5 million of proceeds from the sales of a large portion our non-core Giddings properties.

Cash Flows from Operating Activities

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. As discussed above under the "Delhi Field EOR Project," fiscal year 2014 near term revenues will be impacted by the environmental event and are expected to gradually recover commencing with CO_2 injection resuming in the fourth calendar quarter of 2013.

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 provided by operating activities for the year ended June 30, 2011 were $3.1 million. Cash flows provided by operations included cash receipts of $7.0 million from oil and natural gas sales from our properties in the Giddings Field and the Delhi Field and $0.9 million due to a refund from the carry-back of our 2010 federal income tax loss. Cash payments included $4.5 million for operating expenses, including lease operating expenses, production taxes, salaries and wages, $0.1 million related to our joint interest partner's share of capital expenditures and which are due from our joint interest partner, and $0.2 million in estimated state income taxes.

Cash Flows from Investing Activities

Cash paid for oil and gas capital expenditures during the year ended June 30, 2013 was $4.9 million of these $0.7 million was for leasehold acquisitions, principally in the Mississippian Lime, and $4.2 million was for development activities. Development activities were predominantly in the Mississippian Lime, where one salt water disposal well and two producer wells were completed. 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 $0.25 million CD was rolled over beginning a new annual term.

Oil and gas capital expenditures incurred was $3.4 million for the year ended June 30, 2012. As discussed above, this amount is net of a $1.2 million leasehold cost reduction through offsetting a related payable balance. The $3.4 million incurred amount can be reconciled to $4.9 million of cash capital expenditures on the cash flow statement by adjusting it for related non-cash transactions presented at Note 9—"Supplemental Cash Flow Information".

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.

Oil and gas capital expenditures incurred were $8.9 million for the year ended June 30, 2012. This amount can be reconciled to $7.0 million of cash capital expenditures on the cash flow statement by adjusting them for related non-cash transactions presented at Note 9—"Supplemental Cash Flow Information".

At June 30, 2012 the company had advanced $224,206 of cash for its share of development costs to be incurred by its joint venture partner in the Mississippian 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.

Cash paid for oil and gas capital expenditures during our fiscal year ended June 30, 2011 was $3.5 million, which includes net payments on accounts payable of $0.1 million relating to expenditures for oil and natural gas properties. During the year ended June 30, 2011, we received $0.2 million for a lease sale in the Giddings Field.

During the year ended June 30, 2011, $1.1 million of certificates of deposit matured.

Cash Flows from Financing Activities

In the year ended June 30, 2013, we paid preferred dividends of $0.7 million and made $138,000 of treasury stock purchases through the stock surrender of certain officers in satisfaction of payroll liabilities for contemporaneous restricted stock vesting as described at. Note 7—"Stockholders' Equity." A windfall tax benefit related to stock 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. As a result of the unsecured revolving credit agreement entered into February 2012, the company incurred deferred loan costs of $163,257 during the current year. The facility, with availability of $5.0 million, is yet to be drawn upon.

During the year ended June 30, 2011, we received $0.1 million due to the exercise of stock options and $0.2 million for windfall tax benefit received in 2010.

Capital Budget

We expect to fund all of our fiscal 2014 Capital Plan, totaling at least $18 million, with our $24.8 million of working capital on hand at June 30, 2013, and internally generated funds from operations. Our capital budget includes up to $17 million of development expenditures at Delhi, subject to the actual reversion date of our working interest and the rate at which calendar 2014 capital is expended there. Our budget for the Mississippian Lime project is dependent upon results of the currently ongoing recompletion test and, if elected, the results of a third evaluation well and the participation level of our JV partner. Each well is expected to cost approximately $3.2 million on a 100% working interest basis. Our GARP® business is expected to require $1-3 million, depending upon expansion of the installation agreement currently being finalized and any other new agreement.

Results of Operations

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

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

	Year Ended June 30			
	2013	2012	Variance	% change
Sales Volumes, net to the Company:				
Delhi—crude oil Royalty (Bbl)	180,658	136,074	44,584	32.8%
Other properties				
Crude oil (Bbl)	15,721	15,006	715	4.8%
NGLs (Bbl)	7,272	12,611	(5,339)	(42.3)%
Natural gas (Mcf)	139,006	266,787	(127,781)	(47.9)%
Crude oil, NGLs and natural gas (BOE)	226,819	208,156	18,663	9.0%
Revenue data:				
Delhi—crude oil	$ 19,219,036	$ 15,143,770	$ 4,075,266	26.9%
Other properties				
Crude oil	1,467,365	1,403,645	63,720	4.5%
NGLs	253,167	620,187	(367,020)	(59.2)%
Natural gas	410,352	794,436	(384,084)	(48.3)%
Total revenues	$ 21,349,920	$ 17,962,038	$ 3,387,882	18.9%
Average price:				
Delhi—crude oil	$ 106.38	$ 111.29	$ (4.91)	(4.4)%
Other properties				
Crude oil (per Bbl)	$ 93.34	$ 93.54	$ (0.20)	(0.2)%
NGLs (per Bbl)	34.81	49.18	(14.37)	(29.2)%
Natural gas (per Mcf)	2.95	2.98	(0.03)	(1.0)%
Crude oil, NGLs and natural gas (per BOE)	$ 94.13	$ 86.29	$ 7.84	9.1%
Expenses (per BOE)				
Lease operating expense	$ 7.56	$ 8.21	$ (0.65)	(7.9)%
Production taxes	$ 0.29	$ 0.32	$ (0.03)	(9.4)%
Depletion expense on oil and natural gas properties(a)	$ 5.53	$ 5.22	$ 0.31	6.0%

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

Net income attributable to common shareholders. For the year ended June 30, 2013, we reported a net income of $5,954,126 or $0.19 income per diluted share (which includes $1,531,745 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $21,349,920. This compares to net income of $4,501,739, or $0.14 income per diluted share (which includes $1,475,995 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $17,962,038 for the year ended June 30, 2012. The difference was primarily due to an increase in revenues of $3,387,882 partially offset by $1,515,802 of increased operating expenses. Additional details of earnings components are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2013 increased 9% to 226,819 BOE's compared to 208,156 BOE's for the year ended June 30, 2012. This 18,663 BOE increase is primarily due to a 33% increase of 44,584 BOE at Delhi, together with a 3,017 BOE increase at the Lopez Field, partially offset by a 29,619 BOE decline at the Giddings Field of which approximately 31,618 BOE is attributable to properties divested during fiscal 2013.

Our crude oil sales volumes for the year ended June 30, 2013 included 180,658 barrels from our interests in Delhi and 15,721 barrels principally from our properties in the Giddings and Lopez Fields. Our crude oil sales volumes for the year ended June 30, 2012 included 136,074 barrels from our interests in Delhi and 15,006 barrels primarily from our properties in the Giddings and Lopez Fields. Our NGL volumes for the year ended June 30, 2013 and 2012 were primarily from our properties in the Giddings Field, and declined 5,339 barrels, or 42%, to 7,272 barrels primarily reflecting Giddings properties sold during fiscal 2013. For the corresponding comparative periods, natural gas volumes, from our Giddings Field and Oklahoma properties decreased 128MMCF, or 48%, to 139 MMCF with the decline primarily due to Giddings divestitures during fiscal 2013.

Petroleum Revenues. Total revenue increased $3.4 million, or 19%, to $21.3 million for the year ended June 30, 2013. This was due to a volume increase of 9% together with a 9% increase in average price received ($94 vs. $86) per BOE. The crude oil revenue increase of $4.1million, which includes a $0.5 million revenue decline due to Giddings divestitures, was partially offset a $0.4 million decline in natural gas revenue together with a $0.3 million decrease in NGL revenue, both declines being primarily attributable to the sales of Giddings properties in fiscal 2013.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes of $1.7 million for the year ended June 30, 2013 were flat compared to prior year. Expenditures for three Mississippi Lime wells completed in the current fiscal year together those for Giddings Field GARP® wells were essentially offset by expense declines for the Lopez Field, for a Woodford property shut-in for the current fiscal year and for other Giddings Field properties. A 9% increase in net sales volumes was offset by a decline in lease operating expense and production taxes rate ($7.85 vs. $8.53) per BOE.

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 $1,531,745 (21% of total G&A) and $1,475,995 (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.

Depreciation, Depletion & Amortization Expense ("DD&A"). DD&A increased by 14% to $1,300,207 for year ended June 30, 2013, compared to $1,136,974 for the year ended June 30, 2012. The increase is primarily due to a 9% increase in net sales volumes, and a higher annual depletion rate ($5.53 vs. $5.22) 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.

Year ended June 30, 2012 compared with the year ended June 30, 2011

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

	Year Ended June 30 2012	2011	Variance	% change
Sales Volumes, net to the Company:				
Delhi—crude oil Royalty (Bbl)	136,074	44,141	91,933	208%
Other properties				
Crude oil (Bbl)	15,006	13,824	1,182	9%
NGLs (Bbl)	12,611	18,704	(6,093)	(33)%
Natural gas (Mcf)	266,787	238,608	28,179	12%
Crude oil, NGLs and natural gas (BOE)	208,156	116,437	91,719	79%
Revenue data:				
Delhi—crude oil	$ 15,143,770	$ 4,493,240	$ 10,650,530	237%
Other properties				
Crude oil	1,403,645	1,179,231	224,414	19%
NGLs	620,187	893,525	(273,338)	(31)%
Natural gas	794,436	964,879	(170,443)	(18)%
Total revenues	$ 17,962,038	$ 7,530,875	$ 10,431,163	139%
Average price:				
Delhi—crude oil	$ 111.29	$ 101.79	$ 9.50	9%
Other properties				
Crude oil (per Bbl)	93.54	85.30	8.24	10%
NGLs (per Bbl)	49.18	47.77	1.41	3%
Natural gas (per Mcf)	2.98	4.04	(1.06)	(26)%
Crude oil, NGLs and natural gas (per BOE)	$ 86.29	$ 64.68	$ 21.61	33%
Expenses (per BOE)				
Lease operating expense	$ 8.21	$ 11.16	$ (2.95)	(26.4)%
Production taxes	$ 0.32	$ 0.69	$ (0.37)	(53.6)%
Depletion expense on oil and natural gas properties(a)	$ 5.22	$ 4.55	$ 0.67	15%

(a) Excludes depreciation of office equipment, furniture and fixtures, and other asset amortization totaling $38,167 and $33,600, for the year ended June 30, 2012 and 2011, respectively. For the 2012 period only, other asset amortization of $11,787 is also excluded.

Net income (loss) attributable to common shareholders. For the year ended June 30, 2012, we reported a net income of $4,501,739 or $0.14 income per diluted share (which includes $1,475,995 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $17,962,038. This compares to a loss $241,553, or $0.01 loss per share (which includes $1,536,007 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $7,530,875 for the year ended June 30, 2011. The difference was primarily due to an increase in revenues of $10,431,163 partially offset by $1,795,036 of increased operating expenses, higher income tax expense of $3,252,008 and preferred dividends of $630,391. Additional details of earnings components are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2012 increased 79% to 208,156 BOE, compared to 116,437 BOE for the year ended June 30, 2011.

Our crude oil sales volumes for the year ended June 30, 2012 included 136,074 Bbls of oil from Delhi, 13,160 Bbls of oil from our properties in the Giddings Field in Texas and 1,846 Bbls of oil from our South Texas properties. Our crude oil sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi (of which 19,988 Bbls of oil were sold during the 4th quarter of 2011), 13,434 Bbls from the Giddings Field properties and 390 Bbls from the South Texas properties.

Entirely from our properties in the Giddings Field, our natural gas liquids production was 12,611 and 18,704 Bbls, respectively, for the years ended June 30, 2012 and 2011.

Natural gas production for the year ended June 30, 2012, included 5,840 Mcf from our properties in Oklahoma and 260,937 Mcf from our properties in the Giddings Field. For the year ended June 30, 2011, natural gas production included 3,757 Mcf from our properties in Oklahoma and 234,851 Mcf from our properties in the Giddings Field.

Petroleum Revenues. Total revenue increased 139% for the year ended June 30, 2012. This was due to volume increases of 161% for oil and 12% for natural gas, partially offset by a 33% decline in gas liquids production, and an increase in average price received per BOE, from $65 per BOE for the year ended June 30, 2011 to $86 per BOE for the year ended June 30, 2012.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2012 increased 29% compared to the year ended June 30, 2011, reflecting costs associated with four wells drilled in the Lopez Field and workovers on two of its salt water disposal wells and 3 well bores acquired in the Giddings Fields. Lease operating expense and production taxes per barrel of oil equivalent decreased 28% from $11.85 per BOE during fiscal 2011, to $8.53 per BOE during fiscal 2012.

General and Administrative Expenses ("G&A"). G&A expenses increased 15% to $6.1 million for the year ended June 30, 2012, compared to $5.3 million for the year ended June 30, 2011. The increase primarily reflected higher accrued performance bonus, legal expenses, consulting services, employee pay rate adjustments and board fees. Non-cash stock-based compensation of $1,475,995 (24% of total G&A) and $1,536,007 (29% of total G&A) for the year ended June 30, 2012 and 2011, 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.

Depreciation, Depletion & Amortization Expense ("DD&A"). DD&A increased by 102% to $1,136,974 for year ended June 30, 2012, compared to $563,104 for the year ended June 30, 2011. The increase is primarily due to a 79% increase in net sales volumes, and a higher annual depletion rate ($5.22 vs. $4.55) per BOE. The higher depletion rate is due to our transfer of all remaining non-amortizing/unevaluated leasehold costs to our full cost pool during fiscal 2012, other than our Mississippi Lime acreage.

Year ended June 30, 2011 compared with the year ended June 30, 2010

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

	Year Ended June 30 2011	Year Ended June 30 2010	Variance	% change
Sales Volumes, net to the Company:				
Delhi—crude oil Royalty (Bbl)	44,141	6,333	37,808	597%
Other properties				
Crude oil (Bbl)	13,824	23,416	(9,592)	(41)%
NGLs (Bbl)	18,704	27,820	(9,116)	(33)%
Natural gas (Mcf)	238,608	407,674	(169,066)	(41)%
Crude oil, NGLs and natural gas (BOE)	116,437	125,515	(9,078)	(7)%
Revenue data:				
Delhi—crude oil	$ 4,493,240	$ 485,032	$ 4,008,208	826%
Other properties				
Crude oil	1,179,231	1,703,227	(523,996)	(31)%
NGLs	893,525	1,079,383	(185,858)	(17)%
Natural gas	964,879	1,754,259	(789,380)	(45)%
Total revenues	7,530,875	5,021,901	$ 2,508,974	50%
Average price:				
Delhi—crude oil	$ 101.79	$ 76.59	$ 25.20	33%
Other properties				
Crude oil (per Bbl)	85.30	72.74	12.56	17%
NGLs (per Bbl)	47.77	38.80	8.97	23%
Natural gas (per Mcf)	4.04	4.30	(0.26)	(6)%
Crude oil, NGLs and natural gas (per BOE)	$ 64.68	$ 40.01	$ 24.67	62%
Expenses (per BOE)				
Lease operating expense	$ 11.16	$ 12.88	$ (1.72)	(13.4)%
Production taxes	$ 0.69	$ 0.39	$ 0.30	76.9%
Depletion expense on oil and natural gas properties(a)	$ 4.55	$ 14.10	$ (9.55)	(68)%

(a) Excludes depreciation of office equipment, furniture and fixtures, and other of $33,600 and $48,699, for the year ended June 30, 2011 and 2010, respectively.

Net loss attributable to common shareholders For the year ended June 30, 2011, we reported a net loss of $241,553, or $0.01 loss per share (which includes $1,536,007 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $7,530,875. This compares to a net loss of $2,387,707 or $0.09 loss per share (which includes $2,148,400 of non-cash stock-based compensation expense) on total oil and natural gas revenues of $5,021,901 for the year ended June 30, 2010. The decrease in net loss was primarily due to an increase in our revenues of $2,508,974 and a decrease in operating costs of $1,298,758 (primarily related to a decrease in depreciation, depletion, and amortization). Additional details of the components of net loss are explained in greater detail below.

Sales Volumes. Crude oil, NGLs, and natural gas sales volumes, net to our interest, for the year ended June 30, 2011 decreased 7% to 116,437 BOE, compared to 125,515 BOE for the year ended June 30, 2010.

Our crude oil sales volumes for the year ended June 30, 2011 included 44,141 Bbls of oil from Delhi, 13,434 Bbls of oil from our properties in the Giddings Field in Texas and 390 Bbls of oil from our South Texas properties. Our crude oil sales volumes for the year ended June 30, 2010 included 6,333 Bbls of oil from Delhi (of which 5,721 Bbls of oil were sold during the 4th quarter of 2010) and 23,416 Bbls from our properties in the Giddings Field in Texas.

Our natural gas liquids production was entirely from our properties in the Giddings Field for the years ended June 30, 2011 and 2010.

Natural gas production for the year ended June 30, 2011, included 3,757 Mcfs from our properties in Oklahoma and 234,851 Mcfs from our properties in the Giddings Field. Natural gas production for the year ended June 30, 2010 was entirely from our properties in the Giddings Field.

Petroleum Revenues. Crude oil, NGLs and natural gas revenues for the year ended June 30, 2011 increased 50% from the year ended June 30, 2010. This was due to a 33% increase in liquid volumes, offset by a 41% decline in natural gas production, and a 62% increase in the average price received per BOE, from $40 per BOE for the year ended June 30, 2010 to $65 per BOE for the year ended June 30, 2011.

Lease Operating Expenses (including production severance taxes). Lease operating expenses and production taxes for the year ended June 30, 2011 decreased 17% compared to the year ended June 30, 2010, primarily due to a significant reduction in saltwater disposal costs, due to our Pearson salt water disposal well, and decreased workover costs during the year ended June 30, 2011. Lease operating expense and production taxes per barrel of oil equivalent decreased 11% from $13.27 per BOE during fiscal 2010, to $11.85 per BOE during fiscal 2011.

General and Administrative Expenses ("G&A"). G&A expenses increased 5% to $5.3 million for the year ended June 30, 2011, compared to $5.1 million for the year ended June 30, 2010. The increase was due primarily to an increase in personnel costs of approximately $760 thousand offset by a reduction in stock-based compensation of approximately $600 thousand. We accrued for a cash bonus of $603 thousand for the year ended June 30, 2011, whereas in the prior year the bonus was paid in stock and accrued $587 thousand as stock-based compensation. The remaining increase in personnel costs were due to cost of living adjustments and a lower allocation of engineer costs to properties during the year ended June 30, 2011. Non-cash stock-based compensation of $1,536,007 (29% of total G&A) and $2,148,400 (42% of total G&A) for the year ended June 30, 2011 and 2010, 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.

Depreciation, Depletion & Amortization Expense ("DD&A"). DD&A decreased by 69% to $563,104 for year ended June 30, 2011, compared to $1,818,110 for the year ended June 30, 2010. The decrease is primarily due to a 7% decrease in net sales volumes, and a lower annual depletion rate ($4.55 vs. $14.10) per BOE. Our depletion rate decreased significantly in the fourth quarter of fiscal year 2010, when we first recorded reserves at Delhi of 9.4 million proved oil reserves with associated legacy costs of only $1.2 million transferred to our full cost pool.

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 2013, we saw modest increases in drilling and oilfield services costs over 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 our working interest production increases at our Mississippian Lime Play, reversion of our back-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, 2013, 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	2 - 3 Years	4 - 5 Years	After 5 Years
Contractual Obligations					
Operating lease	490,284	159,011	318,022	13,251	—
Other Obligations					
Asset retirement obligations	615,551	—	—	—	615,551
Total obligations	$ 1,105,835	$ 159,011	$ 318,022	$ 13,251	$ 615,551

Critical Accounting Policies and Estimates

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, 2013, our total unevaluated costs were $4.1 million, all of which was associated with our Mississippi Lime leasehold position in North Central Oklahoma. If these costs were evaluated and included in our full cost pool, with no increases in our proved reserves as of June 30, 2013, our depreciation, depletion and amortization expense would have increased by approximately $16,000.

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, 2013, 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 estimate at June 30, 2013 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $19,000, $40,000 and $64,000, respectively.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and gas reserves. The new rule allows consideration of new technologies in evaluating reserves, 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. The rule did not have a material effect on our financial statements.

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, 2013, we have recorded a valuation allowance for the portion of our net operating loss that is limited by IRS Section 382.

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. Our dividend yield is zero, as we do not pay a dividend. 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, 2013.

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.

Item 8. Financial Statements

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and subsidiaries as of June 30, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2013, 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, 2013, 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 13, 2013 expressed an unqualified opinion on the effectiveness of Evolution Petroleum Corporation's internal control over financial reporting.

/s/ Hein & Associates LLP
Houston, Texas
September 13, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Evolution Petroleum Corporation
Houston, Texas

We have audited Evolution Petroleum Corporation's internal control over financial reporting as of June 30, 2013, 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, 2013, 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, 2013 and 2012, 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, 2013, and our report dated September 13, 2013, expressed an unqualified opinion.

/s/ Hein & Associates LLP
Houston, Texas
September 13, 2013

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Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2013	June 30, 2012
Assets		
Current assets		
Cash and cash equivalents	$ 24,928,585	$ 14,428,548
Certificates of deposit	250,000	250,000
Receivables		
Oil and natural gas sales	1,632,853	1,343,347
Joint interest partner	49,063	96,151
Income taxes	281,970	92,885
Other	918	190
Deferred tax asset	26,133	325,235
Prepaid expenses and other current assets	266,554	233,433
Total current assets	27,436,076	16,769,789
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties—full-cost method of accounting, of which $4,112,704 and $6,042,094 at June 30, 2013 and 2012, respectively, were excluded from amortization	38,789,032	40,476,172
Other property and equipment	52,217	92,271
Total property and equipment	38,841,249	40,568,443
Advances to joint interest operating partner	26,059	1,366,921
Other assets	252,912	250,333
Total assets	$ 66,556,296	$ 58,955,486
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 642,018	$ 407,570
Due to joint interest partner	127,081	3,217,975
Accrued payroll	1,385,494	1,005,624
Royalties payable	91,427	294,013
State and federal taxes payable	233,548	91,967
Other current liabilities	153,182	71,768
Total current liabilities	2,632,750	5,088,917
Long term liabilities		
Deferred income taxes	8,418,969	6,205,093
Asset retirement obligations	615,551	968,677
Deferred rent	52,865	70,011
Total liabilities	11,720,135	12,332,698
Commitments and contingencies (Note 14)		
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, 2013 and 2012, 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 29,410,858 shares at June 30, 2013 and 28,670,424 at June 30, 2012; outstanding 28,608,969 shares and 27,882,224 shares as of June 30, 2013 and 2012, respectively	29,410	28,670
Additional paid-in capital	31,813,239	29,416,914
Retained earnings	24,013,035	18,058,909
	55,856,001	47,504,810
Treasury stock, at cost, 801,889 shares and 788,200 shares as of June 30, 2013 and 2012, respectively	(1,019,840)	(882,022)
Total stockholders' equity	54,836,161	46,622,788
Total liabilities and stockholders' equity	$ 66,556,296	$ 58,955,486

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Year Ended June 30, 2013	2012	2011
Revenues			
Crude oil	$ 20,686,401	$ 16,547,415	$ 5,672,471
Natural gas liquids	253,167	620,187	893,525
Natural gas	410,352	794,436	964,879
Total Revenues	21,349,920	17,962,038	7,530,875
Operating Costs			
Lease operating expenses	1,713,833	1,708,235	1,298,650
Production taxes	66,905	66,764	80,677
Depreciation, depletion and amortization	1,300,207	1,136,974	563,104
Accretion of asset retirement obligations	72,312	77,505	59,913
General and administrative expenses*	7,495,309	6,143,286	5,335,384
Total operating costs	10,648,566	9,132,764	7,337,728
Income from operations	10,701,354	8,829,274	193,147
Other			
Interest income	22,580	25,728	14,214
Interest (expense)	(65,745)	(21,950)	—
Income before income tax provision	10,658,189	8,833,052	207,361
Income tax provision	4,029,761	3,700,922	448,914
Net income (loss) attributable to the Company	6,628,428	5,132,130	(241,553)
Dividends on Preferred Stock	674,302	630,391	—
Net income (loss) attributable to common shareholders	$ 5,954,126	$ 4,501,739	$ (241,553)
Earnings (loss) per common share			
Basic	$ 0.21	$ 0.16	$ (0.01)
Diluted	$ 0.19	$ 0.14	$ (0.01)
Weighted average number of common shares outstanding			
Basic	28,205,467	27,784,298	27,437,496
Diluted	31,975,131	31,609,929	27,437,496

* General and administrative expenses for the year ended June 30, 2013, 2012 and 2011 included non-cash stock-based compensation expense of $1,531,745, $1,475,995 and $1,536,007, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	Year Ended June 30, 2013	2012	2011
Cash Flows From Operating Activities			
Net income (loss) attributable to the Company	$ 6,628,428	$ 5,132,130	$ (241,553)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,341,055	1,150,454	563,104
Stock-based compensation	1,531,745	1,475,995	1,536,007
Accretion of asset retirement obligations	72,312	77,505	59,913
Settlement of asset retirement obligations	(90,531)	(61,936)	(1,847)
Deferred income taxes	2,512,978	2,549,592	380,386
Deferred rent	(17,146)	(15,401)	3,777
Other	—	—	32,080
Changes in operating assets and liabilities:			
Receivables from oil and natural gas sales	(289,506)	216,057	(1,023,038)
Receivables from income taxes and other	(189,813)	(64,194)	687,228
Due to/from joint interest partners	(9,947)	139,705	(87,743)
Prepaid expenses and other current assets	(33,121)	(165,581)	90,652
Accounts payable and accrued expenses	538,057	379,873	497,783
Royalties payable	(202,586)	(448,638)	521,589
Income taxes payable	141,581	9,845	36,778
Net cash provided by operating activities	11,933,506	10,375,406	3,055,116
Cash Flows from Investing Activities			
Proceeds from asset sales	3,479,976	799,610	231,326
Development of oil and natural gas properties	(4,163,080)	(3,291,921)	(2,509,652)
Acquisitions of oil and natural gas properties	(755,194)	(3,768,162)	(997,279)
Capital expenditures for other equipment	—	(61,176)	(864)
Advances to joint venture operating partner	—	(224,206)	—
Maturities of certificates of deposit	—	—	1,100,000
Other assets	(32,160)	(35,056)	(48,702)
Net cash used in investing activities	(1,470,458)	(6,580,911)	(2,225,171)
Cash Flows from Financing Activities			
Proceeds from issuance of preferred stock, net	—	6,930,535	—
Proceeds from issuance of restricted stock	32	—	28
Proceeds from the exercise of stock options	70,719	—	106,049
Purchases of treasury stock	(137,818)	—	—
Preferred stock dividends paid	(674,302)	(630,391)	—
Deferred loan costs	(16,211)	(163,257)	—
Windfall tax benefit	794,569	249,728	173,157
Net cash provided by financing activities	36,989	6,386,615	279,234
Net increase in cash and cash equivalents	10,500,037	10,181,110	1,109,179
Cash and cash equivalents, beginning of period	14,428,548	4,247,438	3,138,259
Cash and cash equivalents, end of period	$ 24,928,585	$ 14,428,548	$ 4,247,438

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statement of Changes in Stockholders' Equity

For the Years ended June 30, 2013, 2012 and 2011

	Preferred		Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value	Shares	Par Value				
Balance, June 30, 2010	—	$ —	27,061,376	$ 27,849	$ 18,532,643	$ 13,798,723	$ (882,022)	$ 31,477,193
Issuance of common stock to certain employees in lieu of cash payment of 2010 bonus	—	—	106,927	107	586,926	—	—	587,033
Issuance of restricted common stock	—	—	303,603	303	(275)	—	—	28
Exercise of stock warrants	—	—	58,350	58	(58)	—	—	—
Exercise of stock options	—	—	86,875	87	105,962	—	—	106,049
Forfeiture of restricted common stock	—	—	(4,215)	(4)	4	—	—	—
Stock-based compensation	—	—	—	—	1,536,007	—	—	1,536,007
Net loss	—	—	—	—	—	(241,553)	—	(241,553)
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
Windfall tax benefit	—	—	—	—	249,728	—	—	249,728
Net income	—	—	—	—	—	5,132,130	—	5,132,130
Preferred Stock 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
Purchases of treasury stock	—	—	(13,689)	—	—	—	(137,818)	(137,818)
Stock-based compensation	—	—	—	—	1,531,745	—	—	1,531,745
Windfall tax benefit	—	—	—	—	794,569	—	—	794,569
Net income	—	—	—	—	—	6,628,428	—	6,628,428
Preferred Stock 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

See accompanying notes to consolidated financial statements.

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 acquisition, exploitation and development of properties for the production of crude oil and natural gas. We acquire properties with known oil and natural gas resources and exploit them through the application of conventional and specialized technology to increase production, ultimate recoveries, or both.

Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of EPM and its wholly-owned subsidiaries: NGS Sub Corp and its wholly owned subsidiary, Tertiaire Resources Company, NGS Technologies, Inc., Evolution Operating Co., Inc. and Evolution Petroleum OK, Inc. 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.

Allowance for Doubtful Accounts. 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. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2013 and 2012, 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.

Note 2—Summary of Significant Accounting Policies (Continued)

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 (the "Full-cost Pool").

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 cost of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes (the "Net Capitalized Costs"), 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, 2013, 2012 or 2011.

Other Property and Equipment. Other property and equipment includes buildings, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets, which ranges from three to seven years. 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 Deferred costs and 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

Note 2—Summary of Significant Accounting Policies (Continued)

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. 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.

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 life of the assets, which ranges from three to seven years.

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

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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.

Liabilities. In March 2013, the FASB issued Accounting Standards Update No. 2013-04 (ASU 2013-04), which updated the guidance in ASC Topic 405, *Liabilities.* The amendments in ASU 2013-04 generally provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of the Update is fixed at the reporting date, except for obligations addressed within existing guidance in GAAP. The guidance requires an entity to measure those obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. The new ASU also requires an entity to disclose the nature and amount of the obligation as well as other information about those obligations. For the Company this guidance will become effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this guidance is not expected to have a material impact on our financial position, cash flows, or results of operations.

Offsetting Assets and Liabilities. In January 2013, the FASB issued ASU No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarifies which instruments and transactions are subject to the offsetting disclosure requirements originally established by ASU 2011-11, which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to a master netting or similar arrangement. The new ASU limits the scope of the disclosures include derivatives, sale and repurchase agreements and reverse sale and repurchase agreements, and securities borrowing and securities lending arrangements. Like ASU 2011-11, the amendments in this update will be effective for fiscal periods beginning on, or after

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3—Recent Accounting Pronouncements (Continued)

January 1, 2013. The adoption of ASU 2013-01 is not expected to have a material impact on our financial position, cash flows, or results of operations.

Note 4—Property and Equipment

As of June 30, 2013 and June 30, 2012 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2013	June 30, 2012
Oil and natural gas properties		
Property costs subject to amortization	$ 42,772,184	$ 40,874,244
Less: Accumulated depreciation, depletion, and amortization	(8,095,856)	(6,440,166)
Unproved properties not subject to amortization	4,112,704	6,042,094
Oil and natural gas properties, net	38,789,032	40,476,172
Other property and equipment		
Furniture, fixtures and office equipment, at cost	322,514	322,514
Less: Accumulated depreciation	(270,297)	(230,243)
Other property and equipment, net	$ 52,217	$ 92,271

Unproved properties not subject to amortization includes unevaluated acreage of $4.1 and $6.0 million as of June 30, 2013 and June 30, 2012, respectively, consisting of properties in the Mississippi Lime in Oklahoma. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis. For the year ended June 30, 2013, we transferred $4.1 million of Mississippi Lime property cost to the full cost pool as initial quantities of hydrocarbon production were indicative of impairment. During the corresponding prior year period, we transferred approximately $2.2 million of impaired assets, reflecting principally Woodford Shale properties, from our unevaluated pool to our full cost pool.

The following table provides a summary of costs that are not being amortized as of June 30, 2013, by the fiscal year in which the costs were incurred:

		During the Year Ended June 30,				
Costs excluded from amortization	**Total**	**2013**	**2012**	**2011**	**2010**	**2009**
Leasehold acquisition costs and other	$ 4,112,704	$ 243,593	$ 3,869,111	$ —	$ —	$ —

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.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4—Property and Equipment (Continued)

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.

The proceeds from these sales were recognized as a reduction of the cost of oil and gas properties.

Note 5—Joint Interest Agreement

Effective April 17, 2012, a wholly owned subsidiary of the Company entered into definitive agreements with Orion Exploration Partners, LLC ("Orion") to acquire and develop interests in oil and gas leases, associated surface rights and related assets located in the Mississippian Lime formation in Kay County in North Central Oklahoma. The Company agreed to contribute cash and a drilling carry to maintain its non-operated working interest in the joint venture. Orion contributed the leases, its portion of the drilling capital, its operating expertise in the area and the Mississippian Lime play. The agreement commits the parties to drill between six and fourteen gross wells by April 17, 2013. To this date, one gross salt water disposal well and two gross producer wells have been drilled and completed pursuant to mutual agreement by the parties.

On May 1, 2013, the Company informed Orion that it has elected to forego payment of the $1.2 million remaining balance of original leasehold purchase cost, thereby reducing our joint venture interest in initial undrilled leasehold from 45% to 33.9% under the terms of the Agreement. Either party now has the right to propose a new well within the joint venture's area of mutual interest with the other party having the rights under a pre-agreed joint operating agreement.

Our participation in this joint venture is reflected on our June 30, 2013 and June 30, 2012 balance sheets by the items below. Included in the $1.4 million June 30, 2012 advance to our joint interest operating partner is an accrued $1,142,716 drilling cash call, which is also reflected in the due to joint interest partner balance.

	June 30, 2013	June 30, 2012
Advances to joint interest operating partner	$ 26,059	$ 1,366,921
Due to joint interest partner	127,081	3,217,975

Note 6—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, 2013 and 2012:

	Year Ended	
	2013	2012
Asset retirement obligations—beginning of period	$ 968,677	$ 859,586
Liabilities incurred	60,143	175,943
Liabilities settled	(51,086)	(61,936)
Liabilities sold	(439,927)	—
Accretion	72,312	77,505
Revisions to previous estimates	5,432	(82,421)
Asset retirement obligations—end of period	$ 615,551	$ 968,677

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7—Stockholders' Equity

Common Stock

On July 2, 2010, an employee of the Company exercised 6,875 stock options granted in 2007 at an exercise price of $2.33 per share. See Note 8.

On July 2, 2010, a total of 4,215 shares of restricted common stock were forfeited by an employee. Total unrecognized stock-based compensation expense related to the shares was $11,621. The shares were cancelled and are available for a future grant in the 2004 Stock Plan. See Note 8.

On August 9, 2010, a total of 30,233 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $156,000, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 8.

On September 10, 2010, the Board of Directors authorized and the Company issued 106,927 shares of common stock from the 2004 Stock Plan to certain employees for the payment of fiscal 2010 bonuses. The value of the shares issued were $587,033, based on the fair market value on the date of issuance, or $5.49 per share. The amount of bonus was accrued as of June 30, 2010, and recognized as a long term liability. On September 10, 2010, the date of the share issuance, the liability was reclassified to additional paid-in capital.

On September 10, 2010, the Board of Directors authorized and the Company issued 240,478 shares of restricted common stock from the 2004 Stock Plan to certain employees as a long-term incentive award. Total unrecognized stock-based compensation expense of $1,320,224 related to the long-term incentive award will be recognized ratably over a four year period as the restricted common stock vests. See Note 8.

On October 1, 2010, a total of 4,845 shares of restricted stock were issued to a new employee as long-term incentive compensation. The value of the shares issued was $29,118, based on the fair market value on the date of issuance. The shares are subject to a four year vesting term. See Note 8.

On December 9, 2010, a total of 28,047 shares of restricted common stock was issued to four outside directors as part of their board compensation for calendar year 2011. The value of the shares issued was $168,000, based on the fair market value on the date of issuance. All issuances of common stock were subject to vesting terms per individual stock agreements, which is generally one year for directors. See Note 8.

On December 21, 2010, an employee of the Company exercised 30,000 stock options granted in 2003 at an exercise price of $0.001 per share. See Note 8.

On February 28, 2011, a former consultant of the Company exercised 50,000 stock options granted in 2005 at an exercise price of $1.80 per share. See Note 8.

On March 31, 2011, 58,350 shares of common stock were issued through a net cashless exercise of placement warrants. The placement warrants, which were issued to Laird Cagan, a related party (See Note 11), in 2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share.

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 unrecognized stock-based compensation expense of $1,029,436 related to the long-term incentive award

Note 7—Stockholders' Equity (Continued)

will be recognized ratably over a four year period as, if and when the restricted common stock vests. See Note 8.

On September 9, 2011, a contractor of the Company net exercised 20,000 stock options issued under the 2004 Stock Plan for a net issuance of 7,941 shares of our common stock. The options were granted in March 2008 at an exercise price of $4.10 per share. See Note 8.

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 8.

On May 3, 2012, we issued Laird Cagan 65,261 shares of common stock through a net cashless exercise of a placement warrant. On May 6, 2005, in connection with a financing transaction, the Company issued the placement warrant to Mr. Cagan, a related party (see Note 11), that gave him the right to purchase 91,200 shares of common stock with an exercise price of $2.50 per share.

On July 9, 2012, a contractor of the Company net exercised 30,000 stock options for a net issuance of 15,512 shares of common stock. The options were granted in March 2008 at an exercise price of $4.10 per share. See Note 8.

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 unrecognized stock-based compensation expense of $1,223,020 related to the long-term incentive award will be recognized ratably over a four year period as the restricted common stock vests. See Note 8.

On November 23, 2012, the Company issued 25,000 shares of restricted stock to a consultant who became an employee in 2013. The value of the shares issued was $191,750, based on the fair market value on the date of issuance. The shares vest over a two year period. See Note 8.

On December 6, 2012, a total of 31,970 shares of our restricted common stock was 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 8.

On December 20, 2012 the Company received 2,137 shares of common stock from Sterling McDonald, Vice-President and Chief Financial Officer of the Company for his payroll tax liability arising from recent vesting of restricted stock. The $7.94 per share acquisition cost per share reflected the weighted-average market price of the Company's shares at the dates vested.

On February 7, 2013, a former consultant cash exercised 50,000 stock options that were granted in February 2006 at an exercise price of $1.41 per share. See Note 8.

On March 8, 2013 Sterling McDonald, Vice-President and Chief Financial Officer of the Company, net exercised 250,000 stock options for a net issuance of 243,725 shares of common stock. The options were granted in November 2003 at an exercise price of $0.25 per share. See Note 8.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7—Stockholders' Equity (Continued)

During March 2013, the Company received 480 shares of common stock from Sterling McDonald, Vice-President and Chief Financial Officer of the Company for his payroll tax liability arising from recent vesting of restricted stock. The $10.22 per share acquisition cost reflected the market price of the Company's shares at the date vested.

On April 1, 2013 Robert Herlin, Chief Executive Officer of the Company, exercised 220,000 stock options granted in September 2003 at an exercise price of $0.001 per share. See Note 8.

During June 2013, the Company received 2,198 shares of common stock from Daryl Mazzanti, Vice-President of Operations of the Company, for his payroll tax liability arising from recent vestings of restricted stock. The $10.59 per share acquisition cost reflected the weighted average market price of the Company's shares at the dates vested.

During June 2013, the Company received 2,200 shares of common stock from Sterling McDonald, Vice-President and Chief Financial Officer of the Company, for his payroll tax liability arising from recent vestings of restricted stock. The $10.59 per share acquisition cost reflected the weighted average market price of the Company's shares at the dates vested.

During June 2013, the Company received 4,544 shares of common stock from Robert Herlin, Chief Executive Officer of the Company, for his payroll tax liability arising from recent vestings of restricted stock. The $10.59 per share acquisition cost reflected the weighted average market price of the Company's shares at the dates vested.

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 only be made by us on or after July 1, 2014 for the stated liquidation value of $25.00 per share plus accrued dividends, or by an acquirer under a change of control prior to such date at redemption prices ranging from $25.25 to $25.75 per share. 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 and $630,391 to holders of our Series A Preferred Stock during the years ended June 30, 2013 and 2012, respectively.

Note 8—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

Note 8—Stock-Based Incentive Plan (Continued)

employees, directors, and consultants of the Company and its subsidiaries under the Natural Gas Systems Inc. 2003 Stock Plan (the "2003 Stock Plan") and the Evolution Petroleum Corporation Amended and Restated 2004 Stock Plan (the "2004 Stock Plan" or together, the "EPM Stock Plans"). Option awards for the purchase of 600,000 shares of common stock were issued under the 2003 Stock Plan. The 2004 Stock Plan authorized the issuance of 6,500,000 shares of common stock. No shares are available for grant under the 2003 Stock Plan and 800,914 shares remain available for grant under the 2004 Stock Plan as of June 30, 2013.

We have also granted common stock warrants, as authorized by the Board of Directors, to employees in lieu of cash bonuses or as incentive awards to reward previous service or provide incentives to individuals to acquire a proprietary interest in the Company's success and to remain in the service of the Company (the "Incentive Warrants"). These Incentive Warrants have similar characteristics of the Stock Options. A total of 1,037,500 Incentive Warrants have been issued, with Board of Directors approval, outside of the EPM Stock Plans. We have not issued Incentive Warrants since the listing of our shares on the NYSE MKT (formerly, the American Stock Exchange) in July 2006.

Stock Options and Incentive Warrants

Non-cash stock-based compensation expense related to Stock Options and Incentive Warrants for the years ended June 30, 2013, 2012 and 2011 was $26,274, $327,776 and $715,027, respectively.

There were no Stock Options granted during the years ended June 30, 2013, 2012 and 2011.

The following summary presents information regarding outstanding Stock Options and Incentive Warrants as of June 30, 2013, and the changes during the fiscal year:

	Number of Stock Options and Incentive Warrants	Weighted Average Exercise Price	Aggregate Intrinsic Value(1)	Weighted Average Remaining Contractual Term (in years)
Stock Options and Incentive Warrants outstanding at July 1, 2012	5,372,820	$ 1.83		
Granted	—	—		
Exercised	(550,000)	$ 0.47		
Cancelled or forfeited	—	—		
Expired	—	—		
Stock Options and Incentive Warrants outstanding at June 30, 2013	4,822,820	$ 1.99	$ 43,020,890	2.6
Vested or expected to vest at June 30, 2013	4,822,820	$ 1.99	$ 43,020,890	2.6
Exercisable at June 30, 2013	4,822,820	$ 1.99	$ 43,020,890	2.6

(1) Based upon the difference between the market price of our common stock on the last trading date of the period ($10.91 as of June 30, 2013) and the Stock Option or Incentive Warrant exercise price of in-the-money Stock Options and Incentive Warrants.

Note 8—Stock-Based Incentive Plan (Continued)

For the year ended June 30, 2013, 550,000 Stock Options exercised with an aggregate intrinsic value of $5,233,480. There were 20,000 Stock Options were exercised during the year ended June 30, 2012, with an aggregate intrinsic value of $54,000. There were 86,875 Stock Options exercised during the year ended June 30, 2011 with an aggregate intrinsic value of $493,923.

A summary of the status of our unvested Stock Options and Incentive Warrants as of June 30, 2013 and the changes during that year ended are presented below:

	Number of Stock Options and Incentive Warrants	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2012	18,922	$ 2.45
Granted	—	—
Vested	(18,922)	$ 2.45
Unvested at June 30, 2013	—	$ —

During the years ended June 30, 2013, 2012, and 2011, there were 18,922, 154,955, and 375,580 Stock Options and Incentive Warrants that vested with a total grant date fair value of $46,359, $336,252, and $739,893, respectively.

There is no unrecognized compensation cost at June 30, 2013, relating to non-vested Stock Options and Incentive Warrants.

Restricted Stock

Stock-based compensation expense related to Restricted Stock grants for the years ended June 30, 2013, 2012, and 2011 was $1,505,471, $1,148,219, and $820,980, respectively. See Note 7 for a detail of Restricted Stock transactions during the years ended June 30, 2013, 2012, and 2011.

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2013:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested at July 1, 2012	452,600	$ 5.16
Granted	211,197	$ 7.88
Vested	(277,198)	$ 5.15
Unvested at June 30, 2013	386,599	$ 6.65

During the years ended June 30, 2013, 2012, and 2011, there were 277,198, 239,195, and 206,858 shares of Restricted Stock that vested with a total grant date fair value of $1,427,570, $1,078,769, and $794,335, respectively.

At June 30, 2013, unrecognized stock compensation expense related to Restricted Stock grants totaled $2,278,014. Such unrecognized expense will be recognized over a weighted average remaining service period of 2.2 years.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9—Supplemental Disclosure of Cash Flow Information

Our supplemental disclosures of cash flow information for the year ended June 30, 2013, 2012, and 2011 are as follows:

	Year Ended June 30, 2013	2012	2011
Income taxes paid	$ 699,874	$ 895,000	$ 229,802
Income tax refunds and net operating loss carry-back received	$ —	$ —	$ 979,177
Non-cash transactions:			
Change in accounts payable used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties	$ 157,675	$ (196,396)	$ (91,483)
Change in due to joint venture partner used to acquire oil and natural gas leasehold interests and develop oil and natural gas properties	$ (1,692,997)	$ 1,958,029	$ —
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	$ 65,575	$ 93,522	$ 15,000

Note 10—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 year ended June 30, 2013, 2012 and 2011. 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, 2009 through June 30, 2012 for federal tax purposes and for the years ended June 30, 2009 through June 30, 2012 for state tax purposes.

The components of our income tax provision (benefit) are as follows:

	June 30, 2013	June 30, 2012	June 30, 2011
Current:			
Federal	$ 857,480	$ 309,632	$ (64,068)
State	659,303	841,698	132,596
Total current income tax provision	1,516,783	1,151,330	68,528
Deferred:			
Federal	2,546,495	2,542,662	360,174
State	(33,517)	6,930	20,212
Total deferred income tax provision	2,512,978	2,549,592	380,386
Total income tax provision	$ 4,029,761	$ 3,700,922	$ 448,914

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10—Income Taxes (Continued)

The 2013 effective rate is in excess of the federal statutory rate primarily due to Louisiana state income tax. The 2012 effective tax rate is in excess of the federal statutory rate primarily due to the incentive based stock compensation and Louisiana state income tax. The 2011 effective rate is well in excess of the federal statutory rate primarily due to the reversal of permanent deductions take in prior years that were recomputed as a result of the federal NOL carryback claims as well as incentive based stock compensation. The rate appears abnormally high as a result of the fixed dollar nature of the permanent items in relation to the nearly breakeven pretax book income. The following is a reconciliation of statutory income tax expense to our income tax provision:

	June 30, 2013	June 30, 2012	June 30, 2011
Income tax provision (benefit) computed at the statutory federal rate:	$ 3,623,784	$ 3,003,238	$ 70,503
Reconciling items:			
State income taxes, net of federal tax benefit	413,019	560,095	100,853
Stock-based compensation (primarily incentive stock options)	8,933	83,115	140,620
Expiring NOLs related to 2004 reverse merger	600,964	4,348,495	
Deferred tax asset valuation adjustment	(600,964)	(4,348,495)	—
Reversal of Section 199 deductions as a result of carry-backs	—	—	141,920
Rate adjustment	—	—	(7,172)
Other	(15,975)	54,474	2,190
Income tax provision	$ 4,029,761	$ 3,700,922	$ 448,914

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

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10—Income Taxes (Continued)

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, 2013	June 30, 2012	June 30, 2011
Deferred tax assets:			
Non-qualified stock-based compensation	$ 774,673	$ 774,720	$ 959,547
Net operating loss carry-forwards	427,249	1,336,769	5,910,275
AMT credit carry-forward*	502,466	714,571	682,456
Other	28,170	29,929	23,626
Gross deferred tax assets	1,732,558	2,855,989	7,575,904
Valuation allowance	(292,446)	(893,410)	(5,187,983)
Total deferred tax assets	1,440,112	1,962,579	2,387,921
Deferred tax liability:			
Oil and natural gas properties	(9,832,948)	(7,842,437)	(5,718,187)
Total deferred tax liability	(9,832,948)	(7,842,437)	(5,718,187)
Net deferred tax liability	$ (8,392,836)	$ (5,879,858)	$ (3,330,266)

* Total AMT credit carry-forward is $632,335. Our net deferred tax liability does not include $129,869 of AMT credit carry-forward associated with the windfall tax benefit.

At June 30, 2013, we have a federal tax loss carry-forward of approximately $1.3 million. This amount is related to tax loss carry-forwards that we acquired through the reverse merger in May 2004, of which, approximately $0.4 million is available to us to use in equal amounts through 2023. We have applied a valuation allowance against the portion of the federal tax loss carry-forward that has been disallowed through IRC Section 382.

Note 11—Related Party Transactions

Laird Q. Cagan, a member of our Board of Directors, is a Managing Director and co-owner of Cagan McAfee Capital Partners, LLC ("CMCP"). CMCP has performed financial advisory services to us pursuant to a written agreement amended in December 2008. Also pursuant to the Agreement, Mr. Cagan, as a registered representative of Colorado Financial Services Corporation and as a partner of CMCP, could serve as our placement agent in private equity financings, wherein CMCP could earn cash fees equal to 8% of gross equity proceeds, declining to 4% subject to the amount of equity raised through CMCP, and a fixed 4% warrant fee. We have not paid placement fees to CMCP under this agreement since May 2006.

On October 27, 2009, we issued CMCP 119,795 shares of common stock through a net cashless exercise of a placement warrant. The placement warrant, which was issued to CMCP on May 26, 2004 in connection with a financing transaction, gave CMCP the right to purchase 165,000 shares of common stock, with an exercise price of $1.00 per share.

On March 31, 2011, 58,350 shares of common stock were issued through a net cashless exercise of placement warrants. The placement warrants, which were issued to Laird Cagan, a related party, in

Note 11—Related Party Transactions (Continued)

2004 in connection with a financing transaction, gave Mr. Cagan the right to purchase 66,943 shares, with a weighted average exercise price of $1.00 per share.

On May 3, 2012, we issued Laird Cagan 65,261 shares of common stock through a net cashless exercise of a placement warrant. The placement warrant, which was issued to Mr. Cagan on May 6, 2005 in connection with a financing transaction, gave him the right to purchase 91,200 shares of common stock, with an exercise price of $2.50 per share.

See also Note 7 for equity transactions with related parties.

Note 12—Net Income (Loss) Per Share

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

	Year Ended June 30, 2013	Year Ended June 30, 2012	Year Ended June 30, 2011
Numerator			
Net income (loss) attributable to common shareholders	$ 5,954,126	$ 4,501,739	$ (241,553)
Denominator			
Weighted average number of common shares—Basic	28,205,467	27,784,298	27,437,496
Effect of dilutive securities:			
Common stock warrants issued in connection with equity and financing transactions	878	63,319	—
Stock Options and Incentive Warrants	3,768,786	3,762,312	—
Total weighted average dilutive securities	3,769,664	3,825,631	—
Weighted average number of common shares and dilutive potential common shares used in diluted EPS	31,975,131	31,609,929	27,437,496
Net income (loss) per common share—Basic	$ 0.21	$ 0.16	$ (0.01)
Net income (loss) per common share—Diluted	$ 0.19	$ 0.14	$ (0.01)

* Potential dilutive common shares are excluded from the computation of net loss per common shares because their effect will always be anti-dilutive.

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

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12—Net Income (Loss) Per Share (Continued)

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

Outstanding potentially dilutive securities as of June 30, 2011 are as follows:

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price		Outstanding at June 30, 2011
Common stock warrants issued in connection with equity and financing transactions	$	2.50	92,365
Stock Options and Incentive Warrants	$	1.85	5,392,820
Total	$	1.86	5,485,185

Note 13—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 four year term. The Company's subsidiaries guaranteed 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 Oil and Gas Properties.

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% and the Federal Funds 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 reflecting 3.5% per annum rate applied to their principal amounts and are due when transacted. Their maximum term is one year.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13—Unsecured Revolving Credit Agreement (Continued)

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 for compensating the Lender $50,000 for incurred loan costs 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 Series A 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 all amounts outstanding under the Credit Agreement to be immediately due and payable.

As of June 30, 2013 and 2012, 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. The Company was in compliance with all the covenants of the Credit Agreement.

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.

Note 14—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.

On March 29, 2012, the Fifth District Court of Richland Parish Louisiana dismissed the case against the Company and our wholly owned subsidiary NGS Sub Corp. brought by John C. McCarthy et. al. (the "plaintiffs") in July 2011. 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. The Court found that plaintiffs had "no cause of action" under Louisiana law. The 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 cause of action. The plaintiffs' have amended their claim and re-filed them with the district court. We have subsequently filed a second motion pleading "no cause of action." This motion is pending.

Note 14—Commitments and Contingencies (Continued)

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 lease, an amount less than our expected cost to prevail in court. The mediated settlement subsequently went to arbitration in February 2013 and the result was essentially the same as the mediated settlement. Execution of the settlement is pending.

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 "Jones lawsuit") in the Western District Court of the Monroe Division, Louisiana. 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. 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). The court's ruling on this motion is pending. Counsel has advised us that, based on information developed to date, the risk of loss in this matter is remote.

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, 2013 under this operating lease are as follows:

For the year ended June 30,	
2014	$ 159,011
2015	159,011
2016	159,011
Thereafter	13,251
Total	$ 490,284

Rent expense for the year ended June 30, 2013, 2012, and 2011 was $147,233, $147,233, and $146,263, respectively.

Employment Contracts. We have entered into employment agreements with the Company's three senior executives. The employment contracts provide for a severance package for termination by the Company for any reason other than cause or permanent disability, or in the event of a constructive termination, that includes payment of base pay and certain medical and disability benefits from six months to a year after termination. The total contingent obligation under the employment contracts as of June 30, 2013 is approximately $663,000.

Note 15—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, 2013, 2012, and 2011. Based on the current demand for oil

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15—Concentrations of Credit Risk (Continued)

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	**2013**	**2012**	**2011**
Plains Marketing L.P. (includes Delhi production)	90%	84%	60%
Enterprise Crude Oil LLC	4%	7%	15%
Flint Hills	2%	1%	—%
DCP Midstream, LP	1%	2%	6%
Kinder Morgan (fka Copano Field Services/Upper Gulf Coast, L.P.)	1%	3%	7%
Enervest, LLC	1%	—%	—%
Orion Exploration Partners, LLC	1%	—%	—%
ETC Texas Pipeline, LTD.	—%	3%	12%

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.

Note 16—Retirement Plan

Effective February 1, 2007, we implemented a 401(k) Savings Plan which covers all full-time employees. At our discretion, we may match a certain percentage of the employees' contributions to the plan. The matching percentage is currently 100% of the first 6% of each participant's compensation, vesting fully upon our contributions. Our matching contribution to the plan was $89,810, $84,738, and $77,168 for the years ended June 30, 2013, 2012, and 2011, respectively.

Note 17—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. Development costs also include amounts incurred due to the recognition of asset retirement

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17—Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

obligations, of $65,575, $93,522, and $15,000, during the years ended June 30, 2013, 2012, and 2011 , respectively.

	For the Years Ended June 30		
	2013	2012	2011
Oil and Natural Gas Activities			
Property acquisition costs:			
Proved property	$ 26,449	$ 115,637	$ 465,176
Unproved property	195,599*	5,544,217	523,591
Exploration costs	4,356,640	3,016,924	215,660
Development costs	79,035	238,463	2,200,905
Total costs incurred for oil and natural gas activities	$ 4,657,723	$ 8,915,241	$ 3,405,332

* Excludes $1,209,197 cost reduction due to reducing the Mississippian Lime joint venture interest in initial undrilled leasehold from 45% to 33.9%. See Note 5—Joint Interest Agreement.

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, 2013, 2012, and 2011, which requires the application of the previous 12-month 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.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17—Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (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, 2010	10,254,470	1,036,627	6,762,954	12,418,256
Revisions of previous estimates	1,475,918	(84,154)	3,273,846	1,937,405
Improved recovery, extensions and discoveries	—	—	779,556	129,926
Sales of minerals in place	(104,577)	(221,469)	(1,173,850)	(521,688)
Production (sales volumes)	(57,965)	(18,704)	(238,607)	(116,437)
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
Sales of minerals in place	—	—	—	—
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	1,826,053	975,515	27,679	2,806,181
Improved recovery, extensions and discoveries	—	—	—	—
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
Proved developed reserves:				
June 30, 2010	706,053	157,302	1,536,858	1,119,498
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

During our fiscal year ended June 30, 2013, total proved reserves increased 0.3 million BOE from 13,441,116 BOE at June 30, 2012 to 13,766,440 BOE at June 30, 2013. The increase is primarily to 2,806 MBOE of upward revisions at Delhi, partially offset by 227 MBOE of production and divestitures of 2,254 MBOE of our Giddings Field properties. The upward revision of 2,806 MBOE in proved reserves in the Delhi Field is due primarily to revision of geological maps based on production results and acquired seismic data, inclusion of one reservoir with similar features, production history and suitability for EOR, and inclusion of natural gas processing at Delhi. Proved developed reserves increased to 73% of proved reserves, a 13% improvement from 60% of proved reserves that were developed at June 30, 2012.

During our fiscal year ended June 30, 2012, total proved reserves decreased 0.4 million BOE from 13,847,462 BOE at June 30, 2011 to 13,441,116 BOE at June 30, 2012. The decrease is primarily attributable to our production, downward revisions of 127 MBOE for our Woodford properties in Oklahoma and 369 MBOE for lease terminations in Giddings Fields, partially offset by a 210 MBOE upward revision at Delhi and 146 MBOE for extensions in South Texas and acquired well bores in the

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17—Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

Giddings Fields. The upward revision in proved oil reserves in the Delhi Field is due primarily to a slight acceleration in the projected reversion date of our approximately 24% working interest based on performance to date.

During our fiscal year ended June 30, 2011, total proved reserves increased 1.4 million BOE from 12,418,256 BOE at June 30, 2010 to 13,847,462 BOE at June 30, 2011. The increase is primarily attributable to upward revisions in both the Delhi Field and our Giddings Field, partially offset by sales in place of reserves in the Giddings Field. The upward revision of 1,475,918 BO in proved oil reserves is due primarily to a more than two year acceleration in the projected reversion date of our 24% working interest, based on operating performance to date. The upward revision of 3,273,846 Mcf is primarily due to re-categorizing probable reserves into the proved category for our properties in the Giddings Field, as a result of drilling results during the year. Sales in place of 521,688 BOE in the Giddings Field are primarily due to the industry drilling joint venture we entered into early in the year.

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, 2013, 2012, and 2011 are as follows:

	For the Years Ended June 30		
	2013	2012	2011
Future cash inflows	$ 1,436,980,607	$ 1,355,686,188	$ 1,161,278,060
Future production costs and severance taxes	(510,902,614)	(458,716,938)	(379,493,392)
Future development costs	(60,742,406)	(38,458,724)	(40,571,895)
Future income tax expenses	(275,113,560)	(296,703,838)	(278,455,798)
Future net cash flows	590,222,027	561,806,688	462,756,975
10% annual discount for estimated timing of cash flows	(283,001,328)	(278,209,195)	(234,309,020)
Standardized measure of discounted future net cash flows	$ 307,220,699	$ 283,597,493	$ 228,447,955

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17—Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited) (Continued)

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12-month 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,					
	2013		2012		2011	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$ 91.51	$ 3.44	$ 95.67	$ 3.15	$ 90.09	$ 4.21

The NGL price that was utilized was based on the historical price received versus the NYMEX basis oil price.

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		
	2013	2012	2011
Balance, beginning of year	$ 283,597,493	$ 228,447,954	$ 161,626,649
Net changes in sales prices and production costs related to future production	(35,184,725)	76,942,613	57,178,860
Changes in estimated future development costs	(566,125)	6,340,123	(16,028,728)
Sales of oil and gas produced during the period, net of production costs	(19,569,182)	(16,187,039)	(6,151,549)
Net change due to extensions, discoveries, and improved recovery	—	1,606,122	623,446
Net change due to revisions in quantity estimates	64,817,544	(11,975,496)	56,766,220
Net change due to sales of minerals in place	(34,119,027)	—	(8,233,734)
Development costs incurred during the period	747,656	(2,639,398)	2,416,565
Accretion of discount	41,678,733	22,568,868	26,597,834
Net change in discounted income taxes	10,175,957	(15,026,628)	(42,490,270)
Other	(4,357,625)	(6,479,626)	(3,857,339)
Balance, end of year	$ 307,220,699	$ 283,597,493	$ 228,447,954

Note 18—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.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 18—Fair Value Measurement (Continued)

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 19—Selected Quarterly Financial Data (Unaudited)

The following table presents summarized quarterly financial information for the years ended June 30, 2013 and 2012:

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 commonsholders	$ 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 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

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19—Selected Quarterly Financial Data (Unaudited) (Continued)

expense, primarily attributable to an increase in accrued bonus, shelf registration costs and an engineering study.

2012	First	Second	Third	Fourth
Revenues	$ 3,884,856	$ 4,646,702	$ 4,848,534	$ 4,581,946
Operating income	$ 2,008,866	$ 2,426,838	$ 2,273,461	$ 2,120,109
Net income available to commonsholders	$ 1,015,683	$ 1,259,950	$ 1,299,525	$ 926,581
Basic net income per share	$ 0.04	$ 0.05	$ 0.05	$ 0.03
Diluted net income per share	$ 0.03	$ 0.04	$ 0.04	$ 0.03

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 the Company's 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, 2013.

The effectiveness of our internal control over financial reporting at June 30, 2013 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 58 of this Report 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, 2013 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

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 2013 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 2013 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 2013 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 2013 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 2013 fiscal year.

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.

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, President and Chief Executive Officer
(Principal Executive Officer)

Date: September 13, 2013

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 13, 2013	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
September 13, 2013	/s/ STERLING H. MCDONALD Sterling H. McDonald	Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
September 13, 2013	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Director
September 13, 2013	/s/ GENE STOEVER Gene Stoever	Director
September 13, 2013	/s/ WILLIAM DOZIER William Dozier	Director
September 13, 2013	/s/ KELLY W. LOYD Kelly W. Loyd	Director
September 13, 2013	/s/ LAIRD Q. CAGAN Laird Q. Cagan	Director

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INDEX OF EXHIBITS

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
2.1	Asset Purchase Agreement for Tullos Field, dated September 3, 2004 (Previously filed as an exhibit to Form 8-K on September 9, 2004)
2.2	Definitive Asset Purchase Agreement, dated as of February 2, 2005, by and between Chadco, Inc., Alan Chadwick McCartney, Sonya McCartney and NGS Sub. Corp. (Previously filed as an exhibit in Form 8-K on February 8, 2005)
2.3	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)
2.4	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)
2.5	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)
2.6	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)
2.7	Agreement and Plan of Reorganization dated as of April 12, 2004 among Reality Interactive, Inc., Reality Acquisition Corp., Global Marketing Associates, Inc., Dean H. Becker and Natural Gas Systems, Inc. (incorporated by reference to the Current Report on Form 8-K/A filed by Natural Gas Systems, Inc. with the Securities and Exchange Commission on April 27, 2004) (Previously filed as an exhibit to Form Schedule 13D on July 11, 2008)
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	Articles of Merger (Previously filed as an exhibit to Form SB-2/A on October 19, 2005)

EXHIBIT NUMBER	DESCRIPTION
4.3	Form of Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.4	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)
4.5	Specimen form of the Company's Common Stock Certificate (Previously filed as an exhibit to Form S-3 on June 19, 2013)
4.6	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)
4.7	Securities Purchase Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.8	Registration Rights Agreement dated as of May 6, 2005, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.9	Stock Grant Agreement, dated as of May 4, 2005, by and between Natural Gas Systems, Inc. and Liviakis Financial Communications, Inc. (Previously filed as an exhibit to the Company's Current Report on Form 8-K on May 11, 2005)
4.10	Herlin Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.11	Revocable Warrant Agreement between Natural Gas Systems, Inc. and Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.12	Amended and Restated Tatum Resources Agreement, dated January 1, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.13	Warrant Agreement between Natural Gas Systems, Inc. and Tatum CFO Partners, LLP, dated January 1, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.14	McDonald Stock Option Agreement, dated April 4, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on April 8, 2005)
4.15	Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.16	Natural Gas Systems, Inc. Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.17	Revocable Warrant Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Prospect Energy Corporation (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)

EXHIBIT NUMBER	DESCRIPTION
4.18	Natural Gas Systems, Inc. Revocable Common Stock Purchase Warrant in favor of Prospect Energy Corporation, dated as of February 2, 2005 (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.19	Registration Rights Agreement, dated as of February 2, 2005, between Natural Gas Systems, Inc. and Holders of Common Stock of Natural Gas Systems, Inc. (Previously filed as an exhibit to the Company's Current Report on Form 8-K on February 8, 2005)
4.20	Form of Registration Rights Agreement (Previously filed as an exhibit to the Company's Current Report on Form 8-K on October 26, 2004)
4.21	2004 Stock Plan (Previously filed as an exhibit to the Company's Definitive Information Statement on Schedule 14C on August 9, 2004)
4.22	2003 Stock Option Plan, adopted September 25, 2003 (Previously filed as an exhibit to the Company's Form 8-K on January 24, 2007)
4.23	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)
4.24	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).
4.25	Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Report on Form 8-K on June 29, 2005)
4.26	Stock Option Agreement, dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)
4.27	Stock Option Grant Agreement dated June 23, 2005 between Natural Gas Systems, Inc. and Daryl V. Mazzanti (Previously filed as an exhibit to the Company's Current Report on Form 8-K on June 29, 2005)
4.28	Securities Purchase Agreement dated as of January 13, 2006, by and between Natural Gas Systems, Inc. and Rubicon Master Fund (Previously filed as an exhibit to the Company's Current Report on Form 8-K on January 20, 2006)
4.29	Third Revocable Warrant Agreement, by and between Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB-2/A on March 3, 2006)
4.30	Third Revocable Warrant Agreement, by and between Prospect Energy Corporation and Natural Gas Systems, Inc., dated January 31, 2006 (Previously filed as an exhibit to Form SB-2/A on March 3, 2006)
4.31	Subordinated Promissory Note, dated March 3, 2006, between Natural Gas Systems, Inc. and Laird Q. Cagan (Previously filed as an exhibit to Form 8-K on March 8, 2006)
4.32	Form of Restricted Stock Agreement (Previously filed as an exhibit to Form 8-K on May 15, 2009)
4.33	Form of Senior Indenture (Previously filed as an exhibit to Form S-3 on May 20, 2013)

EXHIBIT NUMBER	DESCRIPTION
4.34	Form of Subordinated Indenture (Previously filed as an exhibit to Form S-3 on May 20, 2013)
4,35	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	Third Amendment to Consulting Agreement between Liviakis Financial Communications, Inc. and Evolution Petroleum dated November 14, 2006 (Previously filed as an exhibit to Form 10-QSB on February 14, 2007)
10.2	Executive Employment Agreement of Robert S. Herlin, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.3	Executive Employment Agreement of Sterling H. McDonald, dated April 4, 2005 (Previously filed as an exhibit to Form 8-K on April 8, 2005)
10.4	Executive Employment Agreement of Daryl V. Mazzanti, dated June 23, 2005 (Previously filed as an exhibit to Form 8-K on June 29, 2005)
10.5	Master Services Agreement, dated September 29, 2005, by and between the NGS Technologies, Inc. and MTEM, Ltd. (Previously filed as an exhibit on Form 8-K on October 7, 2005)
10.6	Agreement with Chadbourn Securities, Inc., dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.7	Agreement with Cagan McAfee Capital Partners, LLC, dated February 13, 2006 (Previously filed as an exhibit to Form 10QSB on February 14, 2006)
10.8	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)
10.9	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)
10.10	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)
10.11	Gas Purchase and Gas Processing Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and ETC TEXAS PIPELINE LTD. (Buyer) dated October 8, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)
10.12	Gas Purchase Contract by and between EVOLUTION OPERATION CO., INC. (Seller) and DCP MIDSTREAM, LP (Buyer) dated December 1, 2007 (Previously filed as an exhibit to Form 10-K/A on April 7, 2009)
10.13	Gas Purchase and Sale Agreement by and between EVOLUTION OPERATION CO., INC. (Seller) and COPANO FIELD SERVICES/UPPER GULF COAST, L.P. (Buyer) dated February 1, 2009 (Previously filed as an exhibit to Form 10-Q on May 15, 2009)
10.14	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.

EXHIBIT NUMBER	DESCRIPTION
10.15	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)
10.16	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)
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, independent auditors (Filed herein)
23.2	Consent of W. D. Von Gonten & Co. (Filed herein)
23.3	Consent of DeGolyer and MacNaughton (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 Chief Financial Officer Sterling H. McDonald 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 Chief Financial Officer Sterling H. McDonald Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Filed herein)
99.4	The summary of W.D. Von Gonten & Co. Report as of June 30, 2013, on oil and gas reserves (SEC Case) dated July 2, 2013 and certificate of qualification (Filed herein)
99.5	The summary of DeGolyer and MacNaughton's Report as of June 30, 2013, on oil and gas reserves (SEC Case) dated August 20, 2013 and certificate of qualification (Filed herein)
99.6	The summary of Pinnacle Energy Services, LLC Report as of June 30, 2013, on oil and gas reserves (SEC Case) dated June 28, 2013 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

Exhibit 21.1

Evolution Petroleum Corporation—A Nevada Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Vice President, Chief Financial Officer and Treasurer
Daryl V. Mazzanti	Vice President, Operations
David Joe	Controller & Corporate Secretary

Directors:	
Robert S. Herlin	Chairman of the Board
Laird Q. Cagan	Member
Edward J. DiPaolo	Member
Gene Stoever	Member
William Dozier	Member
Kelly Loyd	Member

NGS Sub Corp.—A Delaware Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Chief Financial Officer and Treasurer
David Joe	Secretary

Directors:	
Robert S. Herlin	
Sterling H. McDonald	

Arkla Petroleum, LLC—A Louisiana Corporation

NGS Sub Corp	Member
Robert S. Herlin	Manager
Sterling H. McDonald	Manager

NGS Technologies, Inc.—A Delaware Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Chief Financial Officer and Treasurer
Daryl V. Mazzanti	Vice President, Operations
David Joe	Secretary

Directors:	
Robert S. Herlin	
Daryl V. Mazzanti	

Evolution Operating Co. Inc.—A Texas Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Vice President, Chief Financial Officer, Treasurer and Secretary
Daryl V. Mazzanti	Vice President, Operations
David Joe	Controller

Directors:
Robert S. Herlin
Sterling H. McDonald

Tertiaire Resources Company—A Texas Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Vice President, Chief Financial Officer, Treasurer and Secretary
Daryl V. Mazzanti	Vice President, Operations

Directors:
Robert S. Herlin
Sterling H. McDonald
Daryl V. Mazzanti

Evolution Petroleum OK, Inc.—A Texas Corporation

Officers:	
Robert S. Herlin	President and Chief Executive Officer
Sterling H. McDonald	Vice President, Chief Financial Officer, Treasurer and Secretary
Daryl V. Mazzanti	Vice President, Operations
David Joe	Controller & Secretary

Directors:
Robert S. Herlin
Sterling H. McDonald

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8 and Registration Statement No. 333-188705 on Form S-3 of Evolution Petroleum Corporation of our reports dated September 13, 2013, relating to our audits of the consolidated financial statements and internal control over financial reporting, which appear in this Annual Report on Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2013.

/s/ Hein & Associates LLP
Hein & Associates LLP
Houston, Texas

September 13, 2013

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Exhibit 23.2

W.D. Von Gonten&Co.
Petroleum Engineering
808 Travis, Suite 1200 Houston, Texas 77002 t: 713.224.6333 f: 713.224.6330 www.wdvgco.com

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We, the firm of W. D. Von Gonten & Co., consent to the use of our name and the use of our report regarding Evolution Petroleum Corporation Estimated Proved Reserves and Future Net Revenues "as of July 1, 2006 through July 1, 2013" in the relevant pages of the Form 10-K of Evolution Petroleum Corporation for the fiscal year ended June 30, 2013. We further consent to the incorporation by reference of information contained in our report as of July 2, 2013, in the Evolution Petroleum Corporation Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8 and Registration Statement No. 333-188705 on Form S-3.

Yours truly,

W.D. Von Gonten Jr.

William D. Von Gonten, Jr.
President
TX#73244

September 12, 2013

EXHIBIT 23.3

DEGOLYER AND MACNAUGHTON
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

September 12, 2013

Evolution Petroleum Corporation
2500 CityWest Blvd.
Suite 1300
Houston, Texas 77042

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our letter report dated August 20, 2013, and to the inclusion of information taken from our "Appraisal Report as of June 30, 2013 on Certain Delhi Field Properties owned by Evolution Petroleum Corporation" in the sections Business Strategy-Delhi Field CO2 EOR (Enhanced Oil Recovery) Project, Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in the Form 10-K of Evolution Petroleum Corporation for the year ended June 30, 2013. We further consent to the incorporation by reference of information contained in our report dated August 20, 2013, in the Evolution Petroleum Corporation Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8, and Registration Statement No. 333-188705 on Form S-3.

Very truly yours,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

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Exhibit 23.4

CONSENT OF PINNACLE ENERGY SERVICES, LLC

We have issued our report letter dated June 28, 2013 for 2013 estimates of non-proved reserves and future net cash flows of certain oil and natural gas properties located in Kay County, Oklahoma acquired by Evolution Petroleum Corporation ("Evolution"). As independent oil and gas consultants, we hereby consent to the inclusion of the information contained in our report letter in this Annual Report on Form 10-K of Evolution (this "Annual Report") and to all references to our firm in this Annual Report. We further consent to the incorporation by reference of information contained in our report as of June 30, 2013, in the Evolution Petroleum Corporation Registration Statement No. 333-140182 on Form S-8, Registration Statement No. 333-183746 on Form S-8 and Registration Statement No. 333-188705 on Form S-3.

PINNACLE ENERGY SERVICES, LLC

/s/ JOHN PAUL DICK

Name: John Paul Dick, P.E.
Title: Manager, Registered Petroleum Engineer

September 12, 2013
Oklahoma City, Oklahoma

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EXHIBIT 31.1

CERTIFICATION

I, Robert S. Herlin, President and Chief Executive Officer of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;

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

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

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

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

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

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

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

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

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

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

Date: September 13, 2013	/s/ ROBERT S. HERLIN
	Robert S. Herlin *Chairman, President and Chief Executive Officer*

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EXHIBIT 31.2

CERTIFICATION

I, Sterling H. McDonald, Vice-President and Chief Financial Officer of Evolution Petroleum Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Evolution Petroleum Corporation;

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

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

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

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

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

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

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

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

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

---

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

Date: September 13, 2013

/s/ STERLING H. MCDONALD

Sterling H. McDonald
Vice-President and Chief Financial Officer

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

The undersigned, Robert S. Herlin, President and Chief Executive Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2013 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

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

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

IN WITNESS WHEREOF, the undersigned has executed this certification as of the 13th day of September, 2013.

/s/ ROBERT S. HERLIN

Robert S. Herlin
President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

QuickLinks

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, Sterling H. McDonald, Vice-President and Chief Financial Officer of Evolution Petroleum Corporation (the "Company"), certifies in connection with the filing with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended June 30, 2013 (the "Report") pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to his knowledge, that:

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

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

IN WITNESS WHEREOF, the undersigned has executed this certification as of the 13th day of September, 2013.

/s/ STERLING H. MCDONALD

Sterling H. McDonald
Vice-President and Chief Financial Officer

A signed original of this written statement require d by Section 906 has been provided to Evolution Petroleum Corporation and will be retained by Evolution Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certificate is being furnished to the Securities and Exchange Commission as an exhibit to this Form 10-K and shall not be considered filed as part of the Form 10-K.

QuickLinks

Exhibit 99.4

W.D.Von Gonten&Co.
Petroleum Engineering

808 Travis, Suite 1200 Houston, Texas 77002 713.224.6333 713.224.6330 www.wdvgco.com

July 2, 2013

Mr. Robert Herlin
Evolution Petroleum Corp.
2500 City West Blvd. Suite 1300
Houston, Texas 77042

Re: Evolution Petroleum Corporation
Estimated Reserves and Revenues
"As of" July 1, 2013

Mr. Herlin:

At your request, W.D. Von Gonten & Co. has estimated future reserves and projected net revenues attributable to interests in certain oil and gas properties owned by Evolution Petroleum Corporation (Evolution), "As of" July 1, 2013. The properties represented in this report are located in Duval, Fayette, Grimes, and Webb Counties, Texas. All net revenue projections were prepared utilizing mid-year 2013 SEC pricing, as per SEC guidelines.

Summaries of our conclusions, "As of" July 1, 2013, are as follows:

	Net to Evolution Petroleum Corporation			
SEC Pricing	**Proved Developed Producing**	**Proved Undeveloped**	**Total Proved**	**Total Probable**
Reserve Estimates				
Oil/Cond., Mbbl	59.7	148.8	208.6	530.9
Gas, MMcf	22.8	0.0	22.8	0.0
NGL, Mbbl	8.5	0.0	8.5	0.0
Gas Equivalent, MMcfe	432.3	893.0	1,325.3	3,185.4
Revenues				
Oil, $ (98) %	5,716,604	14,495,257	20,211,861	51,704,176
Gas, $ (0.4) %	73,951	0	73,951	0
NGL, $ (1.6) %	333,189	0	333,189	0
Total, $	6,123,743	14,495,257	20,618,998	51,704,176
Expenditures				
Ad Valorem Tax, $	234,827	553,139	787,966	1,973,031
Severance Tax, $	253,074	666,782	919,856	2,378,392
Direct Operating Expense, $	1,505,215	3,311,430	4,816,645	11,981,093
Variable Operating Expense, $	1,067,826	3,038,215	4,106,041	10,992,569
Transporation Expense, $	81,293	0	81,293	0
Total, $	3,142,235	7,569,565	10,711,802	27,325,078
Investments including Abandonment				
Total, $	64,125	3,021,300	3,085,425	11,178,100
Estimated Future Net Revenues (FNR)				
Undiscounted FNR, $	2,471,060	3,904,392	6,375,451	13,200,996
FNR Disc. @ 10%, $	1,806,842	1,857,251	3,664,093	6,118,337
Allocation Percentage by Classification				
FNR Disc. @ 10%	49.3%	50.7%	100.0%	

*Due to computer rounding, numbers in the above table may not sum exactly.

Report Qualifications

Purpose of Report – The purpose of this report is to provide Evolution with an estimate of future reserves and revenues attributable to certain oil and gas interests owned by Evolution.

Scope of Work – W. D. Von Gonten & Co. was engaged by Evolution to estimate the reserves and revenues associated with the properties included in this report. Once the reserves were estimated, future revenue projections were made based on a SEC constant price deck.

Reporting Requirements – Securities and Exchange Commission (SEC) Regulation S-X 210, Rule 4-10 and Regulation S-K 229, Item 1200 (as revised in December 2008, effective 1-1-10), and Financial Accounting Standards Board (FASB) Statement No. 69 require oil and gas reserve information to be reported by publicly held companies as supplemental financial data. These regulations and standards provide for estimates of Proved reserves and revenues discounted at 10% and based on unescalated prices and costs. Revenues based on alternate product price scenarios may be reported in addition to the current pricing case. Reporting Probable and Possible reserves is optional. Probable and Possible reserves must be reported separately from Proved reserves.

The Society of Petroleum Engineers (SPE) requires Proved reserves to be economically recoverable with prices and costs in effect on the "As of" date of the report. In conjunction with the World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), the SPE has issued *Petroleum Resources Management* System **(2007 ed.),** which sets forth the definitions and requirements associated with the classification of both reserves and resources. In addition, the SPE has issued *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information*, which sets requirements for the qualifications and independence of reserve estimators and auditors.

The estimated Proved and Probable reserves herein have been prepared in conformance with all SEC, SPE, WPC, AAPG, and SPEE definitions and requirements.

Projections – The attached reserve and revenue projections are on a calendar year basis, with the first time period beginning July 1, 2013 and ending December 31, 2013.

Property Discussion

Evolution's operations are centered on two sets of assets, the Giddings field area located in central Texas and the Lopez field in south Texas.

Evolution's first set of assets are located in the Giddings field area spanning over two counties in Texas which include Fayette and Grimes. Within the Giddings field area, there are two reservoirs targeted by Evolution. These two reservoirs are the Austin Chalk and Georgetown. Currently, Evolution is producing from two leases. The net production of these leases is approximately 10 barrels of oil and 18 Mcf of gas per day from the Austin Chalk and Georgetown reservoirs.

Evolution has leased acreage in the South Lopez Unit located in the Lopez field. Lopez field is located on the border of Duval and Webb Counties, Texas. Evolution is currently producing 19 barrels of oil per day from two wellbores and plans to drill 28 wellbores and complete in the Miranda-Jackson reservoir.

Reserves Estimates

Proved Developed Producing – Reserve estimates for the producing properties were based on a combination of the extrapolation of production history and analogy to offset production. Our future projections of the current producing rates were based on the extrapolation of the previous historical production trends adjusting for the current measured rates.

Proved and Probable Undeveloped – The reserve estimations of the 28 wells (six were Proved locations) scheduled for Lopez field were determined by analyzing the results of the current producing well, current injector well which was put onto production before being converted to disposal and the past two infill drilling programs in the 1970's and the 1980's. Initial rates and incremental reserves associated with the additional wells were based on historical production rate increases and test data from the historical infill programs in Lopez field as well as the two currently producing wells.

Reserves and schedules of production included in this report are only estimates. The amount of available data, reservoir and geological complexity, reservoir drive mechanism, and mechanical aspects can have a material effect on the accuracy of these reserve estimates. Due to inherent uncertainties in future production rates, commodity prices, and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

We consider the assumptions, data, methods, and procedures used in this report appropriate hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and future net revenues.

Product Prices

SEC pricing is determined by averaging the first day of each month's closing price for the previous calendar year using published benchmark oil and gas prices. This method renders a price of $91.60 per barrel of oil and $3.44 per MMBtu of gas.

The NGL price that was utilized in this evaluation was based on the historical price received versus the NYMEX basis oil price. The average historical differential received for NGL volumes was extracted from Percent of Proceeds statements from a twelve month time period from May 1, 2012 through April 30, 2013.

Pricing differentials were applied to all properties, on an individual property basis, in order to reflect prices actually received at the wellhead. The price received for the oil production was represented by Evolution as the NYMEX price with a deduction depending on the oil marketer. Pricing differentials typically account for transportation, geographical differentials, and any marketing bonuses or reductions.

Quality adjustments have been applied based on actual BTU factors for each well. A shrinkage factor has been applied based on production volumes versus actual sales volumes. This shrinkage accounts for the generation of natural gas liquids, any line loss, or fuel usage before the actual sales point.

All prices have been held constant throughout the life of the properties.

Lease Operating and Capital Costs

Monthly operating expenses for each well were derived from the average of the 12 month historical cost from May 1, 2012 through April 30, 2013, which were extracted from the profit and loss statements.

Capital costs necessary to perform workover and/or remedial operations were supplied by Evolution for all properties.

All expenses and costs were held constant for the life of the properties with no escalation.

Other Considerations

Abandonment Costs – Cost estimates regarding future plugging and abandonment procedures associated with the remaining properties were supplied by Evolution for the purposes of this report. Based on analysis performed by Evolution, net of salvage, the cost of the plug and abandoning would be $25,000 for the properties located in Giddings field while the scheduled abandonment cost is $10,000 for the properties located in Lopez field. As we have not inspected the properties personally, a third party study would be necessary in order to accurately estimate all future abandonment liabilities.

Additional Costs – Costs were not deducted for depletion, depreciation and/or amortization (a non-cash item), or federal income tax.

Data Sources – Data furnished by Evolution included basic well information, operating cost, capital cost, ownership, pricing, and production information on certain leases.

Context – We specifically advise that any particular reserve estimate for a specific property not be used out of context with the overall report. ***The revenues and present worth of future net revenues are not represented to be market value either for individual properties or on a total property basis. The estimation of fair market value for oil and gas properties requires additional analysis other than evaluating undiscounted and discounted future net revenues.***

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the July 1, 2013 estimated oil and gas volumes. The reserves in this report can be produced under current regulatory guidelines. Actual future commodity prices may differ substantially from the utilized pricing scenario which may or may not extend or limit the estimated reserve and revenue quantities presented in this report.

We have not inspected the properties included in this report, nor have we conducted independent well tests. W.D. Von Gonten & Co. and our employees have no direct ownership in any of the properties included in this report. Our fees are based on hourly expenses and are not related to the reserve and revenue estimates produced in this report.

Thank you for the opportunity to assist Evolution Petroleum Corporation with this project.

Respectfully submitted,

/s/ William D. Von Gonten, Jr., P.E.
William D. Von Gonten, Jr., P.E.
TX #73244

STATE OF TEXAS
WILLIAM D. VON GONTEN JR.
73244
REGISTERED
PROFESSIONAL ENGINEER

/s/ Jason P. Warren
Jason P. Warren

W.D.Von Gonten&Co.
Petroleum Engineering
TX Lic # F-1855

W.D.Von Gonten&Co.
Petroleum Engineering
808 Travis, Suite 1200 Houston, Texas 77002 t: 713.224.6333 f: 713.224.6330 www.wdvgco.com

Qualifications of Reserve Estimator

William D. Von Gonten, Jr, a Registered Texas Professional Engineer, and owner of W.D. Von Gonten and Co. Petroleum Engineering since 1995, is primarily responsible for overseeing the preparation of the reserve report. His professional qualifications meet or exceed the qualifications of reserve estimators set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include: Bachelors of Science degree in Petroleum Engineering from Texas A & M University 1987; member of the Society of Petroleum Engineers , member of the Society of Petroleum Evaluation Engineers; and more than 24 years of practical experience in estimating and evaluating reserve information and estimating and evaluating reserves.

The technical person primarily responsible for the preparation of the reserve report is Jason Warren, Engineer. He earned a Bachelor's of Science degree in Petroleum Engineering at Texas A & M University in 2005. Jason has been employed with W.D. Von Gonten and Co. since graduation in May, 2005. He has more than eight years of experience in the estimation and evaluation of oil and gas reserves. His responsibilities with the company include preparing reserve and economic evaluations, providing engineering support to evaluate drilling locations, recompletion proposals, acquisitions and divestitures and providing reservoir engineering, technical and financial evaluations of O&G assets for various banking and financial institutions.

Jason is also a member of the Society of Petroleum Engineers.

W.D. Von Gonten Jr.

President
September 5, 2013

Exhibit 99.5

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

This is a digital representation of a DeGolyer and MacNaughton report.

Each file contained herein is intended to be a manifestation of certain data in the subject report and as such is subject to the definitions, qualifications, explanations, conclusions, and other conditions thereof. The information and data contained in each file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

August 20, 2013

Evolution Petroleum Corporation
2500 CityWest Blvd, Suite 1300
Houston, Texas 77042

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved, probable, and possible oil, natural gas liquids (NGL), and natural gas reserves, as of June 30, 2013, of certain properties owned by Evolution Petroleum Corporation (Evolution). This evaluation was completed on August 20, 2013. The properties appraised consist of working and royalty interests located primarily in the Delhi field in Louisiana. Evolution has represented that these properties account for 98.4 percent of its proved reserves as of June 30, 2013. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. This report was prepared in accordance with the guidelines specified in Item 1202 (a)(8) of Regulation S–K, and is to be used for inclusion in certain United States Securities and Exchange Commission (SEC) filings by Evolution.

Reserves included herein are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after June 30, 2013. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Evolution after deducting all royalties and interests owned by others.

Values of proved, probable, and possible reserves shown herein are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad

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valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at 10 percent compounded monthly over the expected period of realization.

Estimates of oil, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this report were obtained from Evolution, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Evolution with respect to property interests appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. It was not considered necessary to make a field examination of the physical condition and operation of the properties.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

The proved, probable, and possible reserves estimated for the appraised interests are located in the Holt-Bryant reservoir. This reservoir was originally discovered in 1944, produced under primary means until unitized for water injection in 1953, and was purchased by Denbury Resources (Denbury) in 2006 in order to initiate a carbon dioxide injection program. Average depth is 3,235 feet subsea, and the unit area is about 6,189 acres. Denbury began carbon dioxide injection in 3 patterns in November 2009 and has since expanded to 15 patterns, 12 of which have seen production response to injection. Evolution owns a royalty interest in the unit and obtains an additional working interest after certain payout provisions are reached.

The volumetric method was used to estimate the original oil in place (OOIP). Structure maps were utilized to delineate each reservoir, and isopach maps were utilized to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. Estimates of OOIP were prepared during unitization and later refined during waterflood operations. Cumulative oil recovery before carbon dioxide injection was about 195 million barrels. Estimates of ultimate recovery to result from carbon dioxide injection in the Holt-Bryant reservoir were obtained after applying a recovery factor to an estimated OOIP of 410 million barrels. This recovery factor is based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. Oil production response to the carbon dioxide was observed in March 2010. Based on the production response from a number of producers, and noting the amount of carbon dioxide injection to date, it is estimated that the recovery of proved reserves will be about 13 percent of OOIP, probable reserves about 4 percent of OOIP, and possible reserves about 3 percent of OOIP.

In addition, Evolution has noted that 3 additional reservoirs exist that are suitable for carbon dioxide injection. These are identified as the Baughman, Beard, and May Libby reservoirs. The estimated OOIP of these reservoirs is about 26.3 million barrels. After the pattern area that could be developed was estimated, the oil recovery from these reservoirs was estimated to be 4.106 million barrels. These reservoirs are classified as probable undeveloped and are subject to Denbury expanding its flood program to these reservoirs after Evolution backs into a working interest. An additional 0.548 million barrels was estimated as possible for these 3 projects.

Evolution has represented that processing of produced gas for NGL will begin in 2016. Estimates of proved NGL reserves were based on installation of a chiller to recover pentanes plus. For probable and possible reserves, it was estimated that additional processing for methane, propane, and butane would be applied to the produced gas stream.

Definition of Reserves

Petroleum reserves included in this report are classified by degree of proof as proved, probable, or possible. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–l0(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with

it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Probable reserves – Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (iv) and (vi) of the definition of possible reserves.

Possible reserves – Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

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

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (iii) of the proved oil and gas reserves definition, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be

assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Probable and possible reserves in this report have not been adjusted in consideration of these additional risks and therefore are not comparable with proved reserves.

Primary Economic Assumptions

Revenue values in this report were estimated using the initial prices and costs specified by Evolution. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The prices used in this report are based on SEC guidelines. The assumptions used for estimating future prices and expenses are as follows:

Oil Prices

An oil price differential was calculated from data provided by Evolution. The prices used for this appraisal were calculated by applying this differential to a West Texas Intermediate (WTI) price of $91.51 per barrel and was then held constant for the life of the property. The WTI price of $91.518 is 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 June 30, 2013. The weighted average effective price attributable to the estimated proved reserves over the life of the property was $106.15 per barrel.

NGL Prices

Evolution has represented that the NGL prices were based on a 12-month average price (reference 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, unless prices are defined by contractual arrangements. The volume-weighted average price attributable to the proved reserves was $84.00 per barrel. The price attributable to the probable and possible reserves was

$64.64 per barrel, due to processing additional propane and butane.

Natural Gas Prices

Evolution has represented that the natural gas prices were based on a reference 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, unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials to the EIA Henry Hub reference price of $3.44 per MMbtu furnished by Evolution and held constant thereafter. The volume-weighted average price was $3.254 per Mcf.

Operating Expenses and Capital Costs

Estimates of operating expenses and capital costs based on current costs were used for the lives of the properties with no increases in the future based on inflation. Future expenditures are estimated to be much higher than current levels due to the carbon dioxide injection program, which will continue to be expanded through 2014. Future capital expenditures were estimated using 2013 values and were not adjusted for inflation. Evolution is expected to pay $1.26 per thousand cubic feet (Mcf) of carbon dioxide, based on a rate of 1 percent of oil price plus transportation charges of 20 cents per Mcf through October 2019. After October 2019, the cost was $1.06 per Mcf.

The development of production and the resulting timing of capital expenditures were based on a development plan provided by Evolution. The payout date was estimated by Evolution to be effective on January 1, 2014, based on expenses incurred in remedial action to repair damages from a release of well fluids in June 2013.

Summary and Conclusions

The estimates of net proved, probable, and possible reserves attributable to Evolution from the properties appraised, as of June 30, 2013, are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Net Proved Reserves		
	Oil (Mbbl)	NGL (Mbbl)	Sales Gas (MMcf)
Developed Producing	10,018	0	0
Developed Nonproducing	0	0	0
Undeveloped	2,556	971	0
Total Proved	**12,574**	**971**	**0**
Probable	5,396	1,035	5,889
Possible	3,401	193	566

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

The estimated future revenue to be derived from the production and sale of the net proved, probable, and possible reserves, as of June 30, 2013, of the properties appraised is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing	Proved Developed Nonproducing	Proved Undeveloped	Total Proved	Probable	Possible
Future Gross Revenue, M$	1,063,403	0	352,959	1,416,362	640,017	375,345
Production Taxes, M$	84,204	0	25,141	109,345	70,581	36,539
Ad Valorem Taxes, M$	3,975	0	1,344	5,319	2,335	1,389
Operating Expenses, M$	270,288	0	114,792	385,080	180,389	125,753
Capital Costs, M$	9,184	0	47,410	56,594	18,777	3,113
Abandonment Costs, M$	1,062	0	0	1,062	228	0
Future Net Revenue, M$	694,689	0	164,271	858,960	367,708	208,551
Present Worth at 10 Percent, M$	380,326	0	74,972	455,298	109,339	32,483

Notes:
1. Future income true expenses were not taken into account in the preparation of these estimates.
2. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the June 30, 2013, estimated oil volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

In our opinion, the information relating to estimated proved, probable, and possible reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31 of the Accounting Standards Update 932-235-50, *Extractive Industries — Oil and Gas (Topic 932): Oil and Gas Reserve* Estimation *and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (5), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein, (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year, and (iii) the effective date of this report may not correspond to the end of Evolution's fiscal year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Evolution. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Evolution. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Paul J. Szatkowski, P.E.

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Evolution Petroleum Corporation dated August 20, 2013, and that I, as Senior Vice President, was responsible for the preparation of this letter.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1974; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 39 years of experience in oil and gas reservoir studies and reserves evaluations.

   Signed: August 20, 2013

/s/ Paul J. Szatkowski, P.E.
Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

June 28, 2013

Evolution Petroleum Corp
2500 City West Blvd., Suite 1300
Houston, Texas 77042
Attn: Mr. Daryl Mazzanti

Re: Reserves and Economic Evaluation
Effective July I, 2013
SEC Pricing-Fiscal Year-End 2012-13

EXECUTIVE SUMMARY

An evaluation was performed on primarily undeveloped acreage located in Kay County, Oklahoma in which Evolution Petroleum Corp. ("'Evolution") owns leasehold. The lands are located in thirty-eight sections within six townships (26N, 27N, 28N, Ranges IE, 2E) as depicted (highlighted) on the attached maps. Evolution and another party have acquired approximately 11,878 net acres in the sections and Evolution owns 33.91841% of the leasehold rights acquired (approximately 4,029 acres). The attached Exhibit A is a summary listing of the sections, leased acreage net to Evolution, and the projected working and net interests. Information used in this evaluation was provided by Evolution and their partners, and was supplemented by public data and Pinnacle in-house data.

The primary hydrocarbon target in these sections is the Mississippian formation which is being commercially developed horizontally in multiple counties in Northern Oklahoma and Southern Kansas. including Kay and other Oklahoma Counties located in the eastern part of the play. There are presently two horizontal producing (PDP) wells associated with Evolution's ownership in the 38 sections and there are no horizontal Mississippian wells directly offsetting the acreage. All forecasted undeveloped wells are presently categorized as Non-Proven (Probable).

An engineering analysis and economic evaluation of the producing properties and potential of the undeveloped acreage was prepared using the SEC pricing guidelines for a year-end evaluation and an effective date as of July 1, 2013. The evaluation includes two (2) Proven (Producing) locations, one hundred eleven (111) Non-Proven (Probable) undeveloped locations and eleven (11) disposal wells to be drilled. Summary results of this analysis are provided below and details are presented in referenced attachments.

	#	Est Gross Rem'g Rsvs		Est Net Rem'g Rsvs		Net Capital	Net Rem'g	Net Pres Value
	Wells	Oil.MBO	Gas. MMcf	Oil.MBO	Gas. MMcf	M$	Cashflow, M$	Dic @ 10%, M$
PDP	2	0.51	13.70	0.04	0.94	0	0.65	0.63
Prob UD	111	15,062.70	55,828.92	2,028.03	7,516.63	54,544.09	93,051.96	20,929.59
SWDW	11	0.00	0.00	0.00	0.00	2,237.72	-2,237.72	-1,410.96
Total	124	15,063.21	55,842.61	2,028.06	7,517.57	56,781.81	90,814.88	19,519.25

The results of the evaluations showing forecasts of production, reserves, revenues, and income for the project are presented in a yearly format, and are attached and made part of this evaluation. One-line economic summaries (by well) of the results from the evaluation are also included in the attachments along with a cumulative project net production graph.

Economic Parameters

Future Income

Future net revenue in this report includes deductions for state production taxes. Future net income is after deducting these taxes, future capital costs, and operating expenses, but before consideration of any state and/or federal income taxes. The future net income has not been adjusted for any outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. The future net income has been discounted at various annual rates. including the standard ten percent (10%), to dete1mine its "present worth." The present worth is shown to indicate the effect of time on the value of money.

Pricing

The oil and gas prices employed in this evaluation were determined according to the SEC pricing regulations for year-end evaluations. As stated, it is the un-weighted arithmetic average of the first-day-of-the-month price for each month of the 12-month reporting period. The natural gas price is based on the NYMEX Henry Hub postings and the oil price is based on NYMEX Cushing postings.

Evolution's fiscal year end is on June 30, thus the prices are calculated using July 1, 2012 through June 1, 2013 prices for this analysis. For this period, the unadjusted average NYMEX SEC prices were $91.60/bbl for oil and $3.44/MMBTU for natural gas. These product prices were adjusted to reflect estimated differentials associated with transportation, BTU content, field losses and usage, basis differentials. gathering and processing costs. An oil differential of -3.00 $/BBl was applied to the oil price, and no differential was applied to the gas pricing to account for the projected 1000 BTU gas.

Interests

Net and gross leasehold ownership (acres) by section were provided by Evolution. Working interests for Evolution were calculated by applying their net acres in each section to the standard and normal 640 acre units as shown in the attached Exhibit A. Calculated interests for each section were applied to wells drilled in those sections. The overall average Evolution working interest of all wells is approximately 17% and was applied as the interest in the disposal wells.

Due to Forced Pooling rules where additional interests from owners not capable or desiring to participate in wells can be acquired by participating owners, it is expected - but not incorporated into this evaluation - that Evolution will have working interests greater than their current leasehold position in a majority of future wells.

Development

A one rig development schedule was employed, starting in the summer of 2013. Horizontal Mississippian wells are projected to be drilled at a rate of 1 well per month, with a disposal well drilled every ten wells. A sixty (60) day period from spud to on-line dates was assumed.

Operating Methods, Capital, and Operating Expenses

The Horizontal Mississippian wells will require lifting assistance to produce back frac and reservoir fluids during their life. Some operators choose to initially run electric submersible pumps (ESPs), while others elect to install gas lift mandrels to lift the high initial and possible future volumes of produced fluid. For ESP's, three-phase electricity is necessary, either purchased from local power companies, or produced from rented/purchased gas powered generators. For gas lift, compression and natural gas is required to be injected and if insufficient supply gas is unavailable from the well, must be purchased from a nearby gas line/supplier, also if available. Conventional pumping units will likely be capable of being used after several years of production.

Evolution, as most operators will, have elected to drill a salt water disposal well in conjunction with producing wells, which makes disposal oflarge volumes of water operationally more efficient and significantly more economical than hauling off the water and paying a disposal fee. The Arbuckle fom1ation is a thick (600'-1000'+) dolomitic formation that lies beneath the Mississippian and can take tens of thousands of barrels of water per day for many years. One disposal well is projected for approximately every 10 producing wells.

Reoccurring operating expenses will be higher initially but are expected to decrease over time to a fairly constant monthly expense. Fixed monthly costs are expected to average approximately $3,000 per month while additional variable costs are estimated to be 4.00 $/BBL of oil produced and $0.50/Mcf of gas produced. An additional 0.10 $/BBL for produced water is also included. This provides a model for decreasing operating expenses, however, these operating expense parameters were held constant.

Abandonment costs were assumed to be offset by future salvageable equipment values, which is a reasonable and common assumption for the activities projected and producing wells in the mid-continent region.

The capital expenditure estimated to drill and complete a horizontal Mississippian well was based on AFEs provided by Evolution. The cost to drill and complete a horizontal Mississippian well with approximately 4,000' of lateral is estimated to be $2,900,000. An Arbuckle disposal well and related facilities are estimated to cost approximately $1,228,000.

In addition, the following leasehold investment will be necessary to maintain acreage:

2013:	$	112,000
2014:	$	693,000
2015:	$	201,000

In Oklahoma, a production tax credit allows for severance taxes to be 1% of revenues for the first 4 years of a horizontal weirs production before increasing to 7% thereafter.

Reservoir, Development, and Resenes

Mississippian Formation

The Mississippian formation is a thick and fractured marine carbonate formation lying above the Woodford Shale source rock and below the Pennsylvanian-aged (Cherokee, Red Fork. et al) rocks. The top of the Mississippian is an unconformity. Porosity development, as identified on logs, can occur throughout the reservoir and occurs at different stratigraphic levels -upper and lower -of the Mississpපian formation.

In the Eastern Area, the Mississippian formation ranges in (true vertical) depth from approximately 3,000' to 6000', and in thickness from approximately 200' to over 500'. The zone is comprised primarily of limestone, with areas of low and high concentrations of chert. The Mississippi Chat is the uppermost member of the Misissippian, and is comprised of dolomite, limestone, and tripolitic chert in varying quantities due to the erosion effects of the unconformity, yielding high porosity. The majority of the Mississipian formation has low matrix permeability but is highly fractured, especially in areas with moderate to higher concentrations of chert where the formation will average 4-8% porosity.

The formation is likely a pressure depletion reservoir enhanced by water/fluid expansion. This description is supported by the observance of the gas-oil ratios and water-oil ratios leveling off after "flush" production in both vertical and horizontal wells. Wells east of the Nemaha Ridge are expected to yield less gas -lower Gas-Oil Ratios -than Mississippian wells west of the Nemaha Ridge, although it appears this natural gas has higher BTU's and will yield significant natural gas liquids (NGL) when processed and generate similar total gas revenues as wells in the Western Area.

Tvpe Curve and Estimated Reserves

Forecasts of future rates and reserves for Evolution's projected undeveloped wells are primarily based on a review of public and private production and well perfonnance data on existing analogous wells horizontally drilled in the Mississippian formation east of the Nemaha Ridge. A review of well logs, vertical well performance, reservoir parameters and use of volumetric calculations on the Mississippian formation was also performed.

The undeveloped locations are projected to have average recoverable reserves of approximately 135 MBBLs oil and 500 MMcf gas per well. Although these reserve volumes were used to model all undeveloped locations, actual recoveries are expected to exhibit a significant range above and below the average. Three horizontal wells per section are currently projected with the potential for additional wells in some sections.

Initial (first day) well rates of 253 BOPD and 410 Mcf/d were estimated based on the review of analogy well perfonnances. Production is expected follow a hyperbolic decline with initial decline rates of 99.99417% for oil and 91.669% for gas (as defined in the PhdWin economics program) and a hyperbolic exponent ("b" factor) of 1.50, which accounts for the production transitioning from early transient flow to (pseudo) steady-state flow through the multiple porosity, permeability, and fracture systems within the reservoir. Oil cuts will also vary by well and area, but are expected to range between 5-15%.

Reserve Classifications

Remaining recoverable reserves are those quantities of petroleum that are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty depending primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty is conveyed by classifying reserves as Proved (highly certain) or Non-Proved (less certain).

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geological and engineering data. can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs. and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing for 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 reasonable time.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved Developed Producing (PDP) is assigned to wells with sufficient production history to allow material balance and decline curve analysis to be the primary methods of estimation. PDP reserves are the most reliable reserves, generally with a high degree of confidence that actually recovered quantities will equal or exceed published reserve estimates.

Proved Developed Non-Producing (PNP) reserves include reserves from zones that have been penetrated by drilling but have not produced sufficient quantities to allow material balance or decline curve analysis with a high degree of confidence. This category includes Proved Developed Behind-Pipe (PNPBP) zones and tested wells awaiting production equipment (PNP).

Proved undeveloped (PUD) oil and gas reserves are 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. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with reasonably certainty that there is continuity of production from the existing productive fom1ation. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. The Proven Undeveloped and Non-Producing wells were forecasted based on geological data presented, volumetric calculations, and analog comparisons to existing completions. Non-Proven (Probable) Undeveloped locations have been evaluated to be more likely than not to be commercially productive but do not meet SEC criteria to be classified as Proved at this time.

General

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserve estimates were performed using accepted engineering practices and were primarily based on volumetric analysis and analogy performance. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future. The revenue from such reserves and the actual costs related may be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Therefore, in all cases. estimates of reserves may increase or decrease as a result of future operations.

In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting, rather than engineering interpretation, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and such conclusions necessarily represent only informed professional judgments.

The titles to the properties have not been examined nor has the actual degree or type of interest owned been independently confirmed. A field inspection of the properties is not usually considered necessary for the purpose of this report.

Information included in this report includes the graphical decline curves for individual wells, projected production and cashtlow economic results by entity, one-line economic results summaries for each well. and miscellaneous individual well information. Additional information reviewed will be retained and is available for review at any time. Pinnacle Energy Services. L.L.C. can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Pinnacle Energy Services, LLC

/s/ Richard J. Morrow

Richard J. Morrow, P.E.

Petroleum Engineer

John Paul Dick, P.E.
Petroleum Engineer

Qualifications of Reserve Estimator

John Paul (J.P.) Dick, P.E., a Registered Professional Engineer in the States of Oklahoma and Texas, and founder of Pinnacle Energy Services, LLC, since 1998, is primarily responsible for overseeing the preparation of the reserve report. His professional qualifications meet or exceed the qualifications of reserve estimators set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include: Bachelor's of Science degree in Petroleum Engineering from The University of Tulsa, 1983; member of the Society of Petroleum Engineers, member of the Society of Petroleum Evaluation Engineers; and more than 29 years of practical experience in estimating and evaluating reserve information and estimating and evaluating reserves.

The technical person primarily responsible for the preparation of the reserve report is Richard J. (Dick) Morrow, P.E., a Registered Petroleum Engineer in the States of Oklahoma and Wyoming. He earned a Bachelor's of Science degree in Petroleum Engineering from the University of Kansas in 1976. Richard joined Pinnacle in 2012 as a consulting petroleum engineer. Prior employment includes Devon Energy, Woods Petroleum and Exxon Mobil. He has over thirty years of experience in oil and gas reservoir studies and reserves evaluations. Richard is also an active member of the Society of Petroleum Engineers.